IREMB appendix report

WP1 scenario analyses

Sorknæs, Peter; Lund, Henrik

Publication date:
2019

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- WP1 scenario analyses

Peter Sorknæs and Henrik Lund

Department of Planning, Aalborg University

Contents

1 Introduction

The purpose of this appendix report is to show the detailed results of the scenario analyses carried out as part of Work Package 1 (WP1) of the research project "Innovative re-making of markets and business models in a renewable energy system based on wind power" (IREMB), that has received funding from the Danish research programme ForskEL.

The purpose of the study is to analyse and quantify the effect of more renewable energy into the current electricity market regime, Nord Pool Spot, in different future energy system scenarios for Denmark. The analyses focus on operational aspects and profit of the different energy technologies different energy system scenarios. Different existing published scenarios have been used for the analyses, that show how different actors see the potential future Danish energy system. The following scenarios have been used as part of the IREMB WP1 work:

- Danish Energy Agency's fossil scenario from 2014 (DEA fossil)
- Danish Energy Agency's wind scenario from 2014 (DEA wind)
- The Danish Society of Engineers energy vision from 2015 (IDA)

Each of these three scenarios shows a potential future development of the Danish energy system. Each scenario is modelled for the years 2035 and 2050. The two Danish Energy Agency (DEA) scenarios are based on [1] from 2014, where the DEA investigates different future energy system scenarios for the Danish energy system. The DEA fossil scenario is a scenario where fossil fuels can still be utilised, and the DEA wind scenario is a scenario where in 2050 the energy system is based solely on renewable energy, mainly wind power. The Danish Society of Engineers energy vision (IDA) scenario is from "IDA's Energy Vision 2050" [2] developed in 2015, and shows a pathway for going towards a 100% renewable Danish energy system in 2050.

The operation of each scenario is calculated in three different fuel price levels (basic, low, and high) and five different price levels on the external electricity markets. The different price levels can be found in [2]. Each scenario is in this report presented separately for each of the two years.

All scenarios are modelled in the energy system simulation tool EnergyPLAN v13.2 [3], where a series of simulations have been done of each. The IDA scenario has originally been developed using a previous version, namely EnergyPLAN v12.4, while the DEA scenarios have originally been developed in an internal DEA energy system analysis tool, and afterwards have been implemented into EnergyPLAN v12.4 as described in [2]. Through the work in the IREMB project the market simulation method used in EnergyPLAN has been improved in order to better analyse the operation of the different technologies. Likewise, the work in other research projects have improved different aspects of EnergyPLAN. As such, since the development of the IDA scenario and the original implementation of the DEA scenarios into EnergyPLAN v12.4, EnergyPLAN have been updated with new and improved functionalities. Thus, in order to utilise the DEA and IDA scenarios in the IREMB project, an update of models was done in order to make full use of the new EnergyPLAN v13.2. The following chapter covers the adjustments made to the DEA and IDA scenarios, made through the IREMB project.

2 Update of DEA and IDA EnergyPLAN models

This chapter is divided into; adjustments due to changes made to EnergyPLAN between v12.4 and v13.x, other adjustments made to the EnergyPLAN models, and lastly an overview of the overall scenario result differences is presented.

The updated EnergyPLAN models do not affect the overall conclusions made in the original "IDA's Energy Vision 2050" [2] from 2015.

2.1 Adjustments made due to changes in EnergyPLAN version 13.x

- As of EnergyPLAN v13.0 electrolysers are categorised and operated differently than in earlier versions of EnergyPLAN, see [3] for more information. To make the models work in EnergyPLAN v13.x, the electrolyser capacities are combined into one category and the investment costs are adjusted accordingly. The total installed capacity and investment cost of electrolysers is not changed, but the electrolysers operate more flexible.
- As of EnergyPLAN v13.1 an option was added to change how EnergyPLAN operates compared with the external electricity market, see [3] for more details. This option has been used for the scenarios in the update, as it provides an operation of the energy system that more correctly reflects the interaction with the surrounding electricity markets.

2.2 Other adjustments made to the EnergyPLAN models

- The distribution for the cooling demand has been changed to instead use an hourly district cooling distribution from 2015.
- In the IDA scenarios, the electricity transmission capacity to surrounding countries has been changed to be the actual capacity in 2015 plus any new transmission capacity already decided to be build (Kriegers Flak of 0.4 GW and the COBRAcable of 0.7 GW).
- The capacity factor of wave power has been changed to from 0.05 to 0.4 in 2035 and from 0.05 to 0.51 in 2050.
- The investment, lifetime, and fixed O&M has been clarified for certain technologies. Table 1 provides an overview of the numbers used in the updated versions of the models. Technologies not shown and data marked with "-" in the table remain unchanged compared with the original "IDA's Energy Vision 2050" report [2].

Technology	Investment [MEUR/unit]		Lifetime [Years]		Fixed O&M [% of inv.]	
	2035	2050	2035	2050	2035	2050
CHP2	1.2	1.2	-	-	3.75	-
CHP3	1.395	0.8	32	-	3.3	-
Heat storage CHP	-	-	20	-	-	-
PP1	1.395	0.9	32	27	3.3	3.26
Offshore wind power	-	-	-	-	2.94	-
Geothermal heat	250	250	25	25	2.45	2.45
Individual boilers	5.8	6.75	21	20	2.6	0.37
Individual heat pumps	11.5	11.5	20	-	0.98	0.98
Individual solar thermal	-	-	30	-	1.35	-

Table 1 – New investment, lifetime and fixed O&M used in the update of "IDA's Energy Vision 2050" [2]

- To reflect the current investments in biomass CHP units in large district heating areas in Denmark, the IDA2035 scenario has been adjusted so that the central CHP units and power plants use 50% gas and 50% biomass. The efficiencies and costs (see Table 1) have been adjusted accordingly.
- The sensitivity analyses with low and high fuel price now use the fuel price levels shown in the original "IDA's Energy Vision 2050" report [2].
- In the IDA scenarios, the district heating boilers are for the most part used as backup boilers, as such, they have been changed to wood pellet boilers. The extra fuel cost for using wood pellets has been added in the EnergyPLAN models as an increased cost for variable OM.
- The capacity of the district heating storage has been changed to 112 GWh in both 2035 and 2050.
- A minor error in the calculation of upgraded biogas in the IDA scenarios was found. The correct amounts of upgraded biogas are 9.31 TWh in IDA2035 and 15.12 TWh in IDA2050.
- The distributions for onshore and offshore wind power have been changed from being based on actual production data in 2013 to instead be production of the share of wind power capacity installed in Denmark with production in 2013, using the stamdata register from the Danish Energy Agency [4] to estimate this capacity in each hour. The annual production for both onshore and offshore wind power is unchanged compared with the original DEA and IDA scenarios.

2.3 Comparison between original and adjusted scenarios

The most significant differences between the original results shown in "IDA's Energy Vision 2050" [2], and the updated EnergyPLAN models used for the IREMB project are:

- In the updated IDA scenario for 2035 the gas consumption has increased by about 25 TWh/year, and the biomass consumption for the same scenario has decreased by about 30 TWh/year, resulting in a small decrease in primary energy supply of about 5 TWh. The lower consumption is especially due to a lower electricity production from power plants.
- In the updated IDA scenario for 2050 the CHP units are operating less, and instead the power plants are operating more, resulting in a minor increase in fuel consumption costs and O&M costs, which also results in a decrease in Electricity exchange costs. This also results in an increased biomass consumption for scenarios where there is an exchange of electricity with surrounding countries.
- In the updated DEA wind 2050 scenario the power plants are operating less, resulting in a small reduction in fuel consumption costs and O&M costs, this also results in an increase in Electricity exchange costs. Also, the DEA wind 2050 scenario has a biomass consumption that is about 5 TWh lower.
- The difference in total annual costs are larger between the three fuel cost scenarios for the 2035 scenarios and the DEA fossil 2050 scenario.
- Electricity consumption capacity for "Smart transport", as shown in Figure 13 in the "IDA's Energy Vision 2050" report, are based on peak hourly electricity consumption in the simulation. Due to the changed hourly simulation in EnergyPLAN, electricity consumption capacity for "Smart transport" has changed in the updated scenarios, which is especially visible in the IDA 2050 scenario, where the electricity consumption capacity goes from about 4.6 GW to about 7.4 GW.

Figure 1 shows the primary energy supply for the different updated EnergyPLAN models.

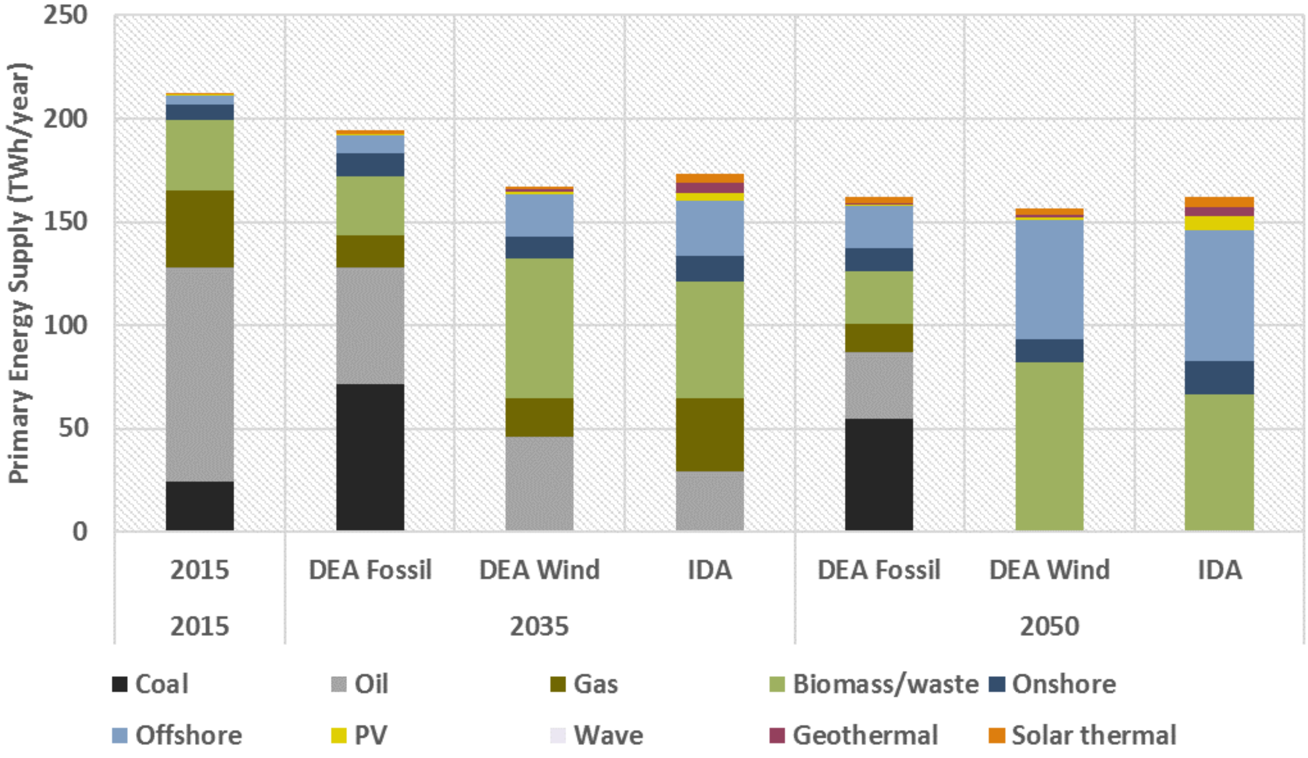

Figure 1 - Primary Energy supply in 2035 and 2050 in the IDA Energy Vision, in 2015 and in the DEA scenarios

Figure 2 shows the updated socio-economic costs for the different scenarios.

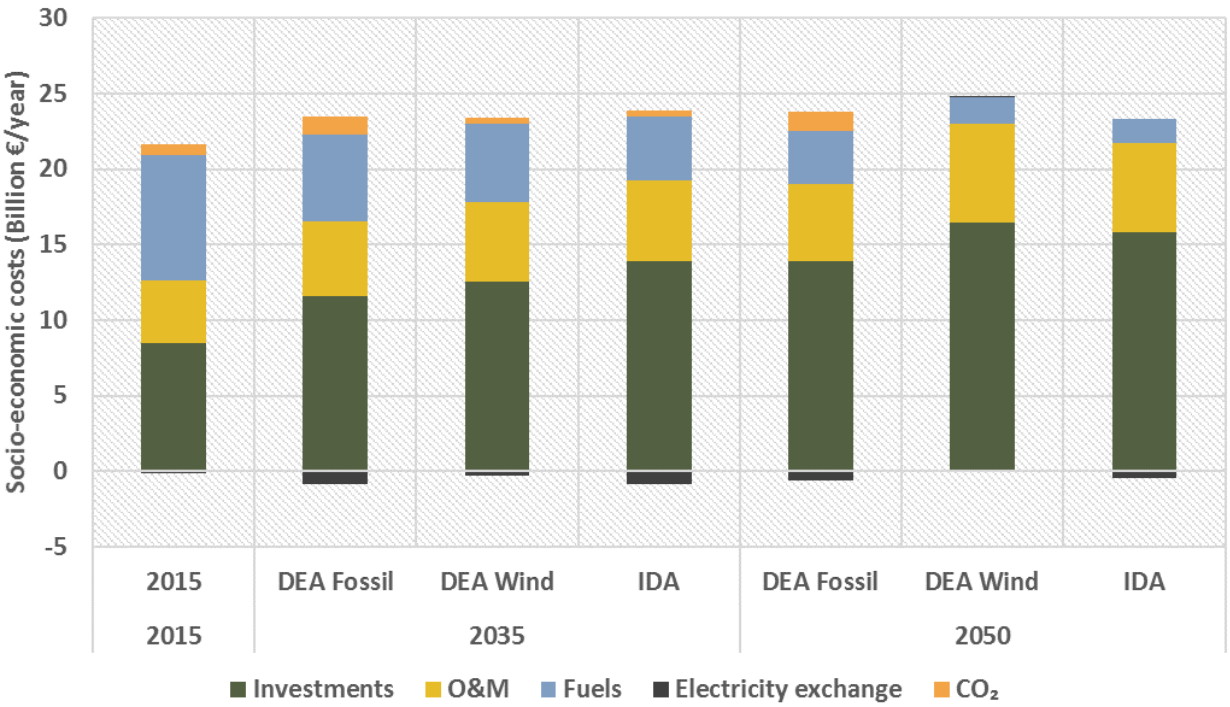

Figure 2 - Socio-economic costs of the energy systems analysed including transport. Net earnings on international electricity markets are illustrated as a negative and should be subtracted to get the total costs of the systems

Figure 1 and Figure 2 are updated versions of Figure 3 and Figure 4 in [2]. Comparing these it is clear that the update models show similar results, with the only major differences being those mentioned above.

3 DEA fossil 2035

3.1 Overview of scenario

Table 2 shows an overview of the main technical and economic characteristic of the electricity producing and main electricity consuming units in the scenario.

General data for units							
	Electric capacity	Electric efficiency	Thermal capacity	Thermal efficiency	Total investment	Annualised investment	Annual fixed O&M
	[MW]	*[%]*	*[MW]*	*[%]*	*[M EUR]*	*[M EUR/a]*	*[M EUR/a]*
Electricity producing units							
Wind - onshore	3500	-	-	-	3500	201	91
Wind - offshore	2150	-	-	-	5224	300	136
PV	800	-	-	-	656	28	7
Wave and river	0	-	-	-	0	0	0
Small CHP	1424	49%	1250	43%	1153	66	43
Large CHP (excl. Condensing)	2154	39%	2872	52%	4286	185	133
- Large CHP condensing operatio	*2776*	*46%*	-	-	*1238*	*54*	*38*
Power plants	1000	45%	-	-	1990	86	62
Flexible electricity consumption units							
Small DH HP	0	-	-	-	0	0	0
Large DH HP	0	-	-	-	0	0	0
Electrolysers	0	-	-	-	0	0	0

Table 2 – Overview of relevant units' capacities, efficiencies, investment costs, and annual fixed operation and maintenance (O&M)

For "Large CHP (excl. Condensing)", the capacities and efficiencies are only for CHP operation. "Large CHP condensing operation" is the full condensing capacity of the large CHP units, where the investment and fixed O&M costs cover the difference between the electric capacity in CHP operation and the condensing electric capacity.

Figure 3 shows the yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh).

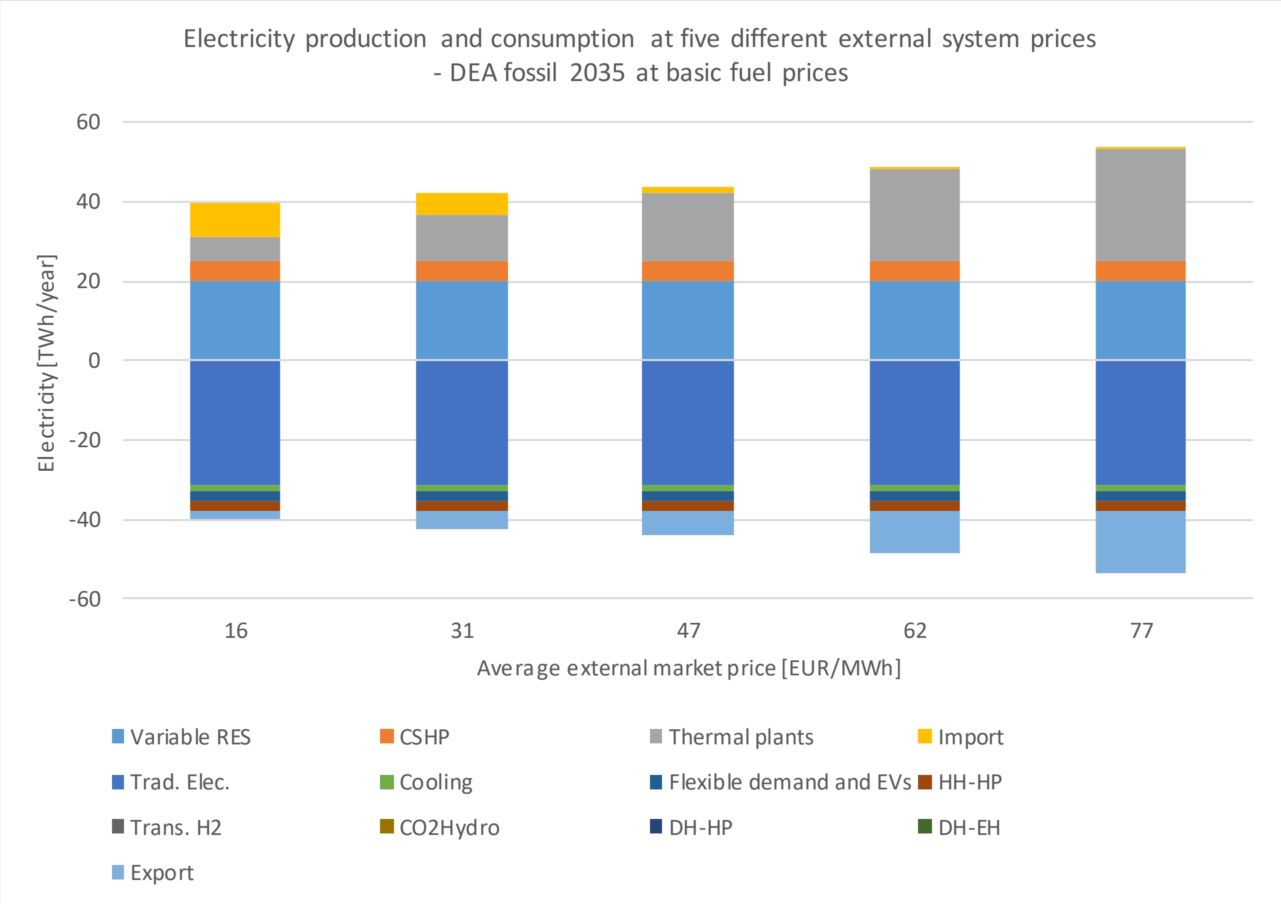

Figure 3 - Yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). RES: Renewable Energy Sources, CSHP: Industrial Combined Heat & Power (incl. waste incineration), HH: Households, HP: Heat Pumps, EV: Electric Vehicle, DH: District Heating, EH: Electric Heating.

3.2 Duration curves for electricity consumption and production

The duration curves shown in this section are only for the average external electricity market price of 77 EUR/MWh.

Figure 4 show the duration curves for different types of residual electricity demands. Residual electricity demand is here understood as the electricity demand minus the variable renewable energy sources' (RES) electricity production in any given hour. "Residual hourly fixed" are demands that are fixed on an hourly basis (includes e.g. traditional electricity demands). "Residual hourly and yearly fixed" are both the "Residual hourly fixed" as well as any electricity demands that are fixed on a yearly basis (includes e.g. flexible charged electric vehicles). "All residual" are all residual electricity demands (includes e.g. heat pumps in district heating). Figure 5 show the electricity production duration curves for Industrial Combined Heat & Power (incl. waste incineration) (CSHP), variable RES, and thermal plants.

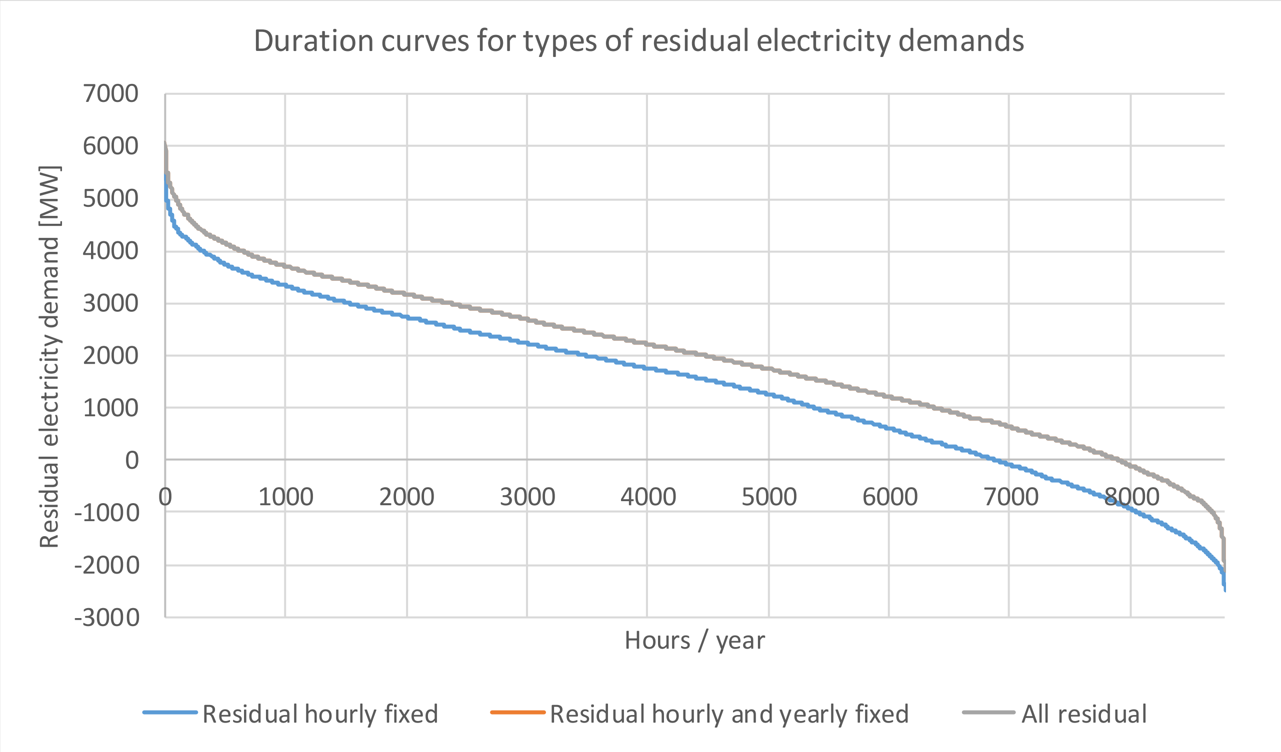

Figure 4 – Duration curves for different types of residual electricity demands at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

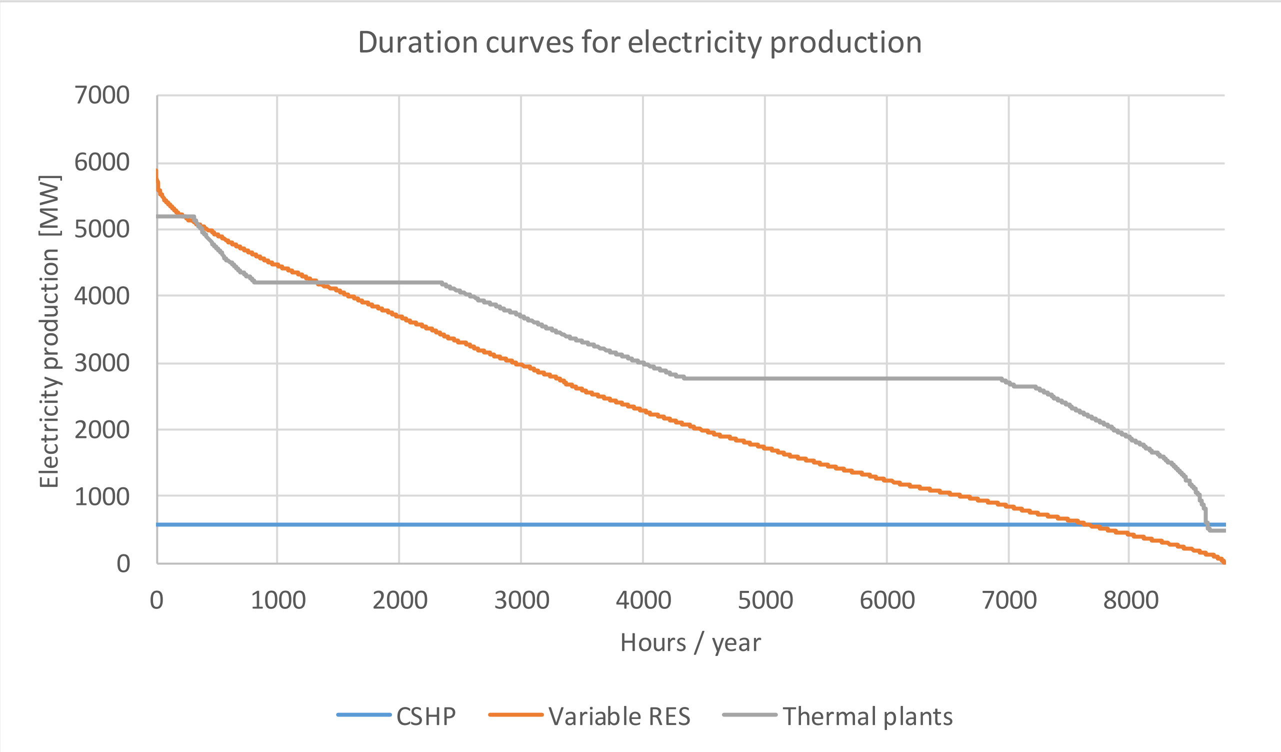

Figure 5 – Duration curves for electricity production by different unit types at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

3.3 Electricity prices

Figure 6, Figure 7, and Figure 8 show for each of the three fuel price levels the resulting hourly electricity market system price using five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). Table 3, Table 4, and Table 5 show the corresponding resulting average, minimum, and maximum electricity price in the simulation.

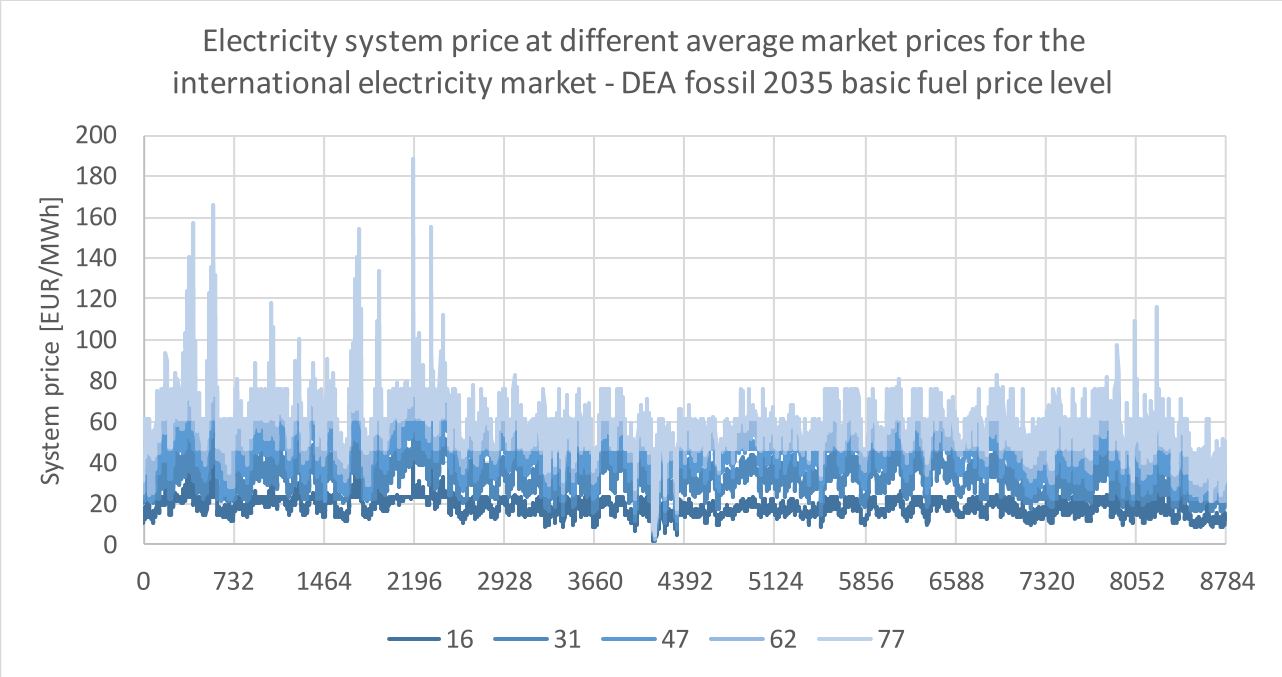

Figure 6 – Hourly system price on Nord Pool Spot at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	18	32	44	52	58
Resulting min	2	2	3	3	4
Resulting max	53	76	113	151	188

Table 3 – Resulting yearly average, minimum and maximum electricity prices at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

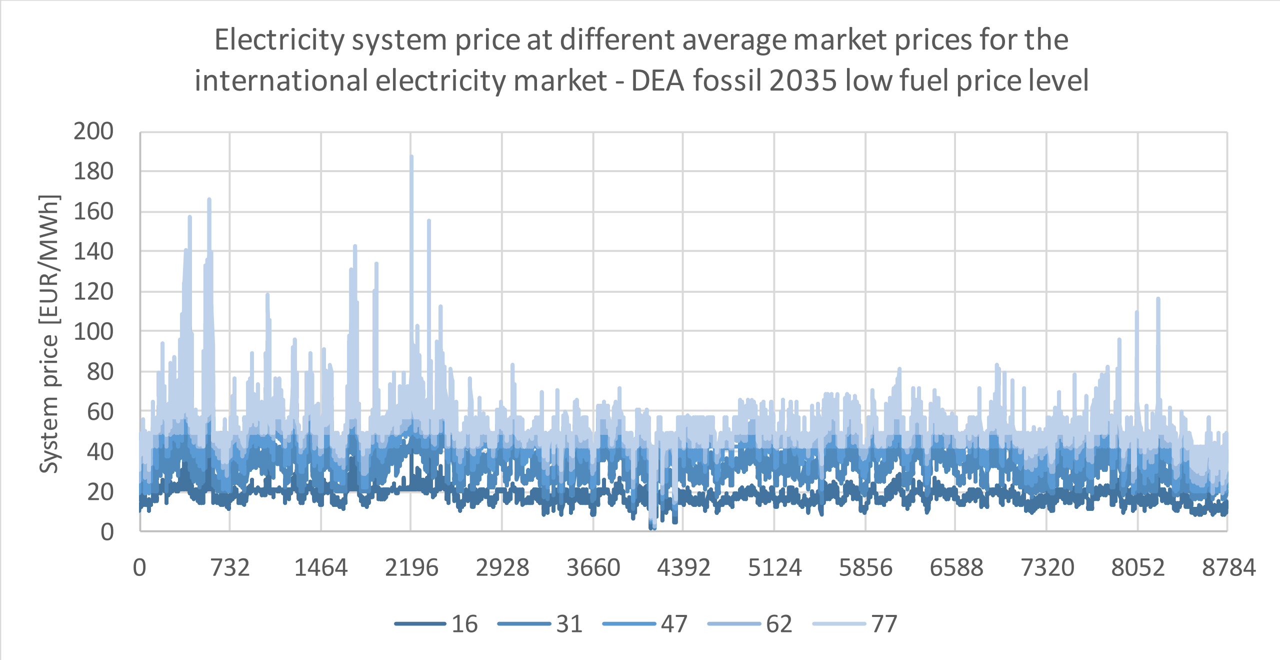

Figure 7 – Hourly system price on Nord Pool Spot at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	18	31	41	47	53
Resulting min	2	2	3	3	4
Resulting max	49	76	113	151	188

Table 4 - Resulting yearly average, minimum and maximum electricity prices at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

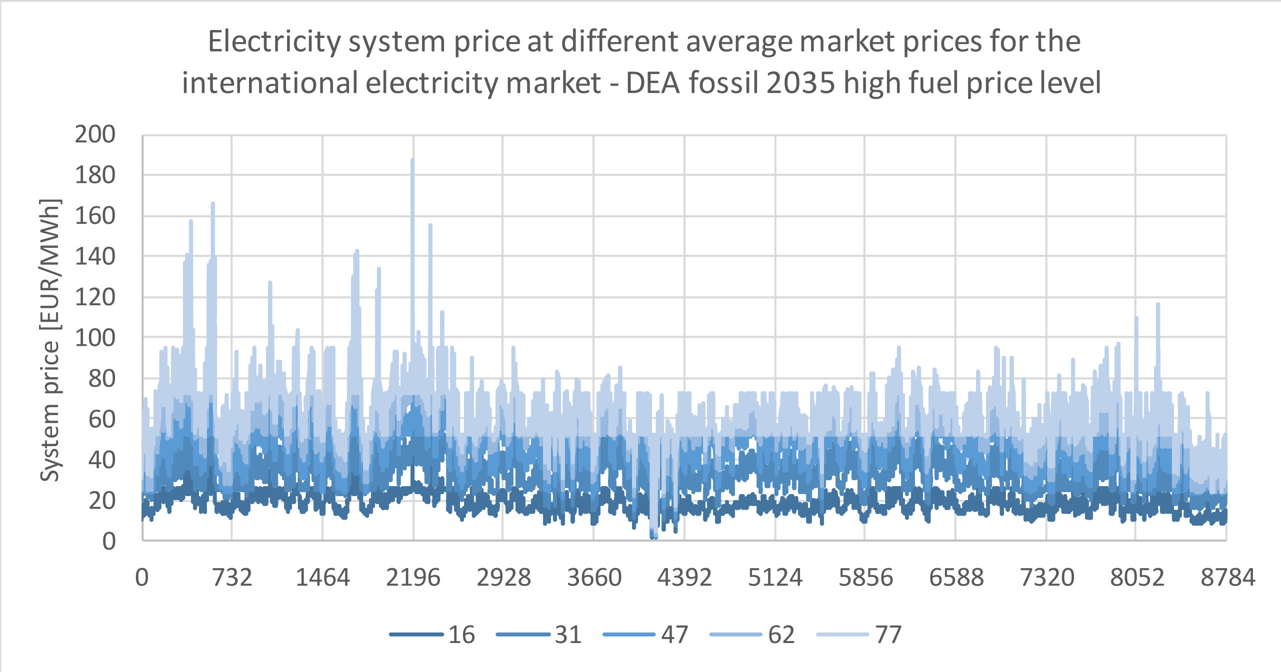

Figure 8 – Hourly system price on Nord Pool Spot at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	18	32	45	55	62
Resulting min	2	2	3	3	4
Resulting max	53	88	113	151	188

Table 5 - Resulting yearly average, minimum and maximum electricity prices at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

3.4 Marginal activated unit

The purpose of this section is to identify the marginal activated unit in the simulated energy system. This is done by first separating the array for the electricity market price into arrays with the marginal price of each unit being the lower limit of an array and the next marginal most expensive unit being the upper limit. E.g. “Incr. B2 decr. EB2” has a marginal price of 38 and the next least expensive unit is “Incr. CHP2 decr. B2” with a marginal price of 67, resulting in the “Incr. B2 decr. EB2” array being prices between 38 and 67. After the arrays have been established, it is for each hour checked whether the activated technology was in fact in use or not. If not, then if there is variable RES in operation this becomes the marginal activated unit. If there is no variable RES in operation, then it that hour is added to the “Rest” category (i.e. the external market is the marginal “unit”). This approach only account for the units activated within the simulated energy system and does not account for what units are activated outside of the simulated energy system in case of import and export of electricity.

This is done for each of the three fuel price levels as well as the five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). See Figure 9, Figure 10, and Figure 11.

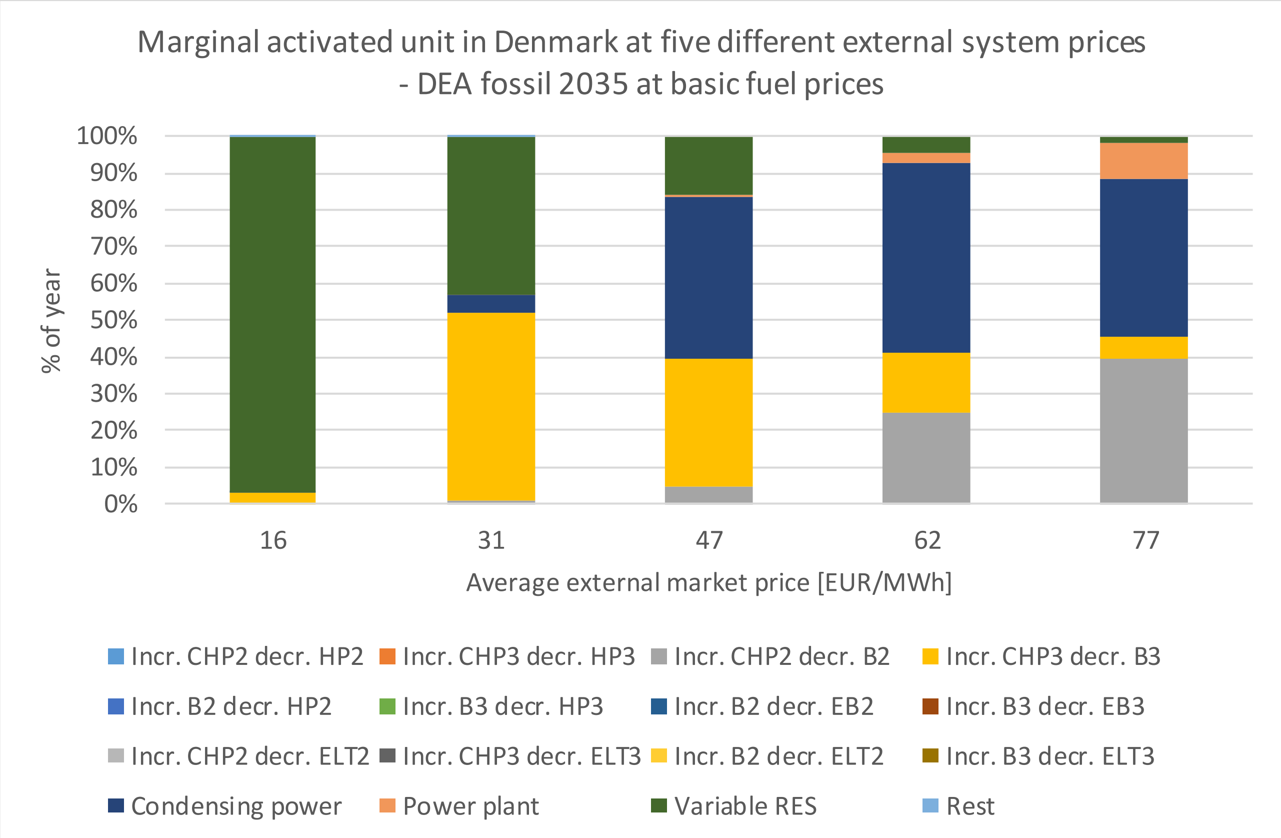

Figure 9 – Marginal activated unit in Denmark at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

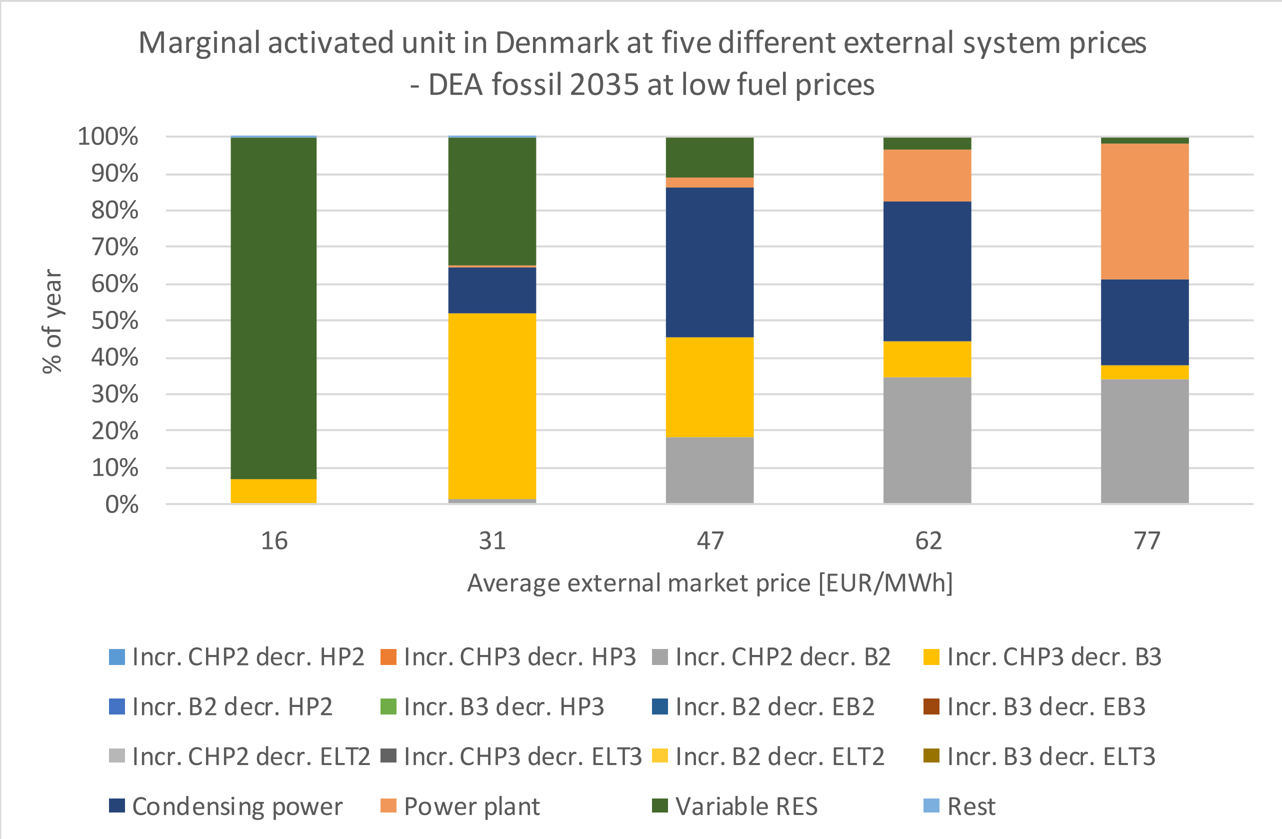

Figure 10 – Marginal activated unit in Denmark at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

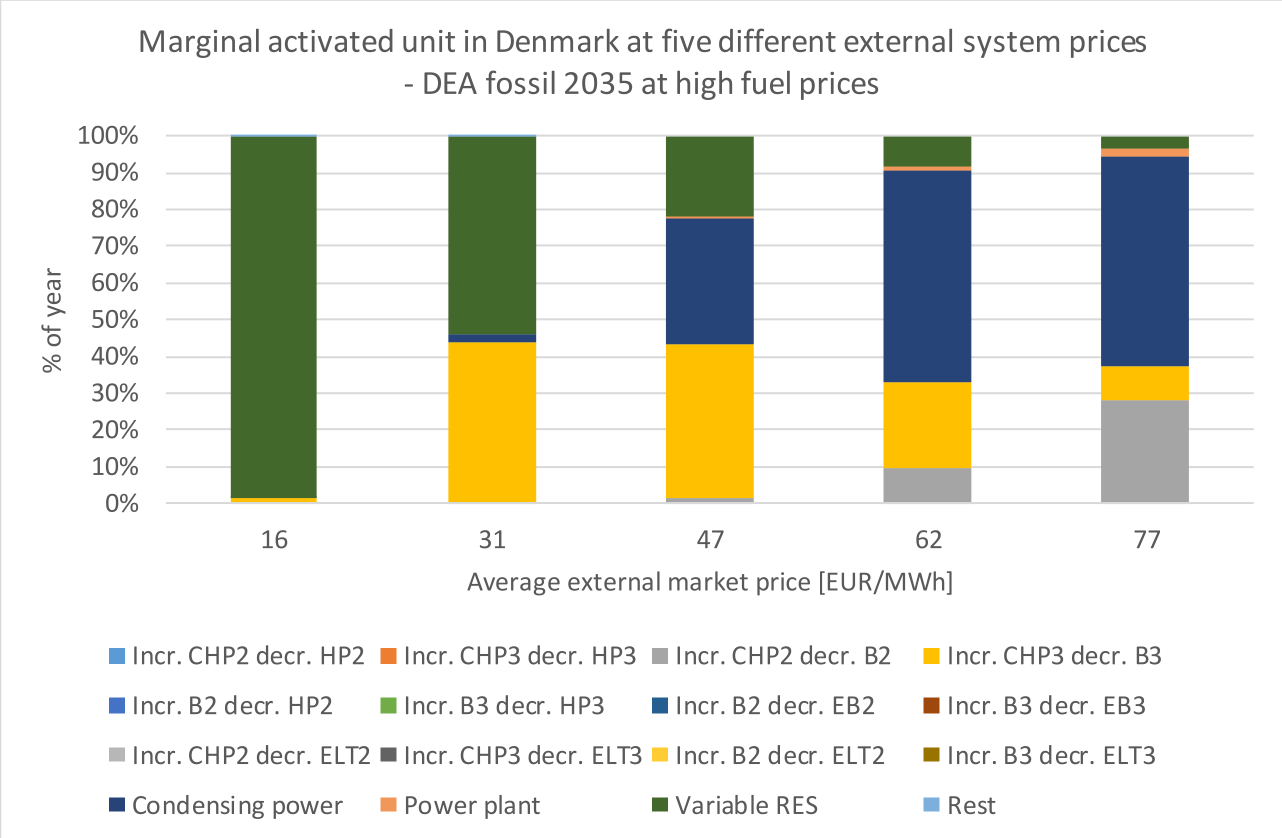

Figure 11 - Marginal activated unit in Denmark at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

3.5 Profit analysis

The aim of this analysis is to identify which types of units are expected to be able to cover their own costs in the current Nord Pool Spot regime. Only costs directly related to the specific units are included (investment, fixed operational and maintenance (O&M), variable O&M, fuel costs, and CO_2-costs). As such, potential related costs, e.g. grid costs and storage costs, are not included. For the income, only sale of electricity on Nord Pool Spot (as modelled in EnergyPLAN) and sale of produced district heating are included. For sale of district heating, it is assumed that the value of the produced heat is equal to the short-marginal cost of an average fuel boiler in the corresponding district heating group.

Figure 12, Figure 14, and Figure 16 show the yearly profit of each unit type where a discount rate of 3% has been used. Figure 13, Figure 15, and Figure 17 show the corresponding internal rate of return (IRR), with only incomes being sale of electricity on Nord Pool Spot and sale of heat for district heating. Each figure represents a different fuel price level.

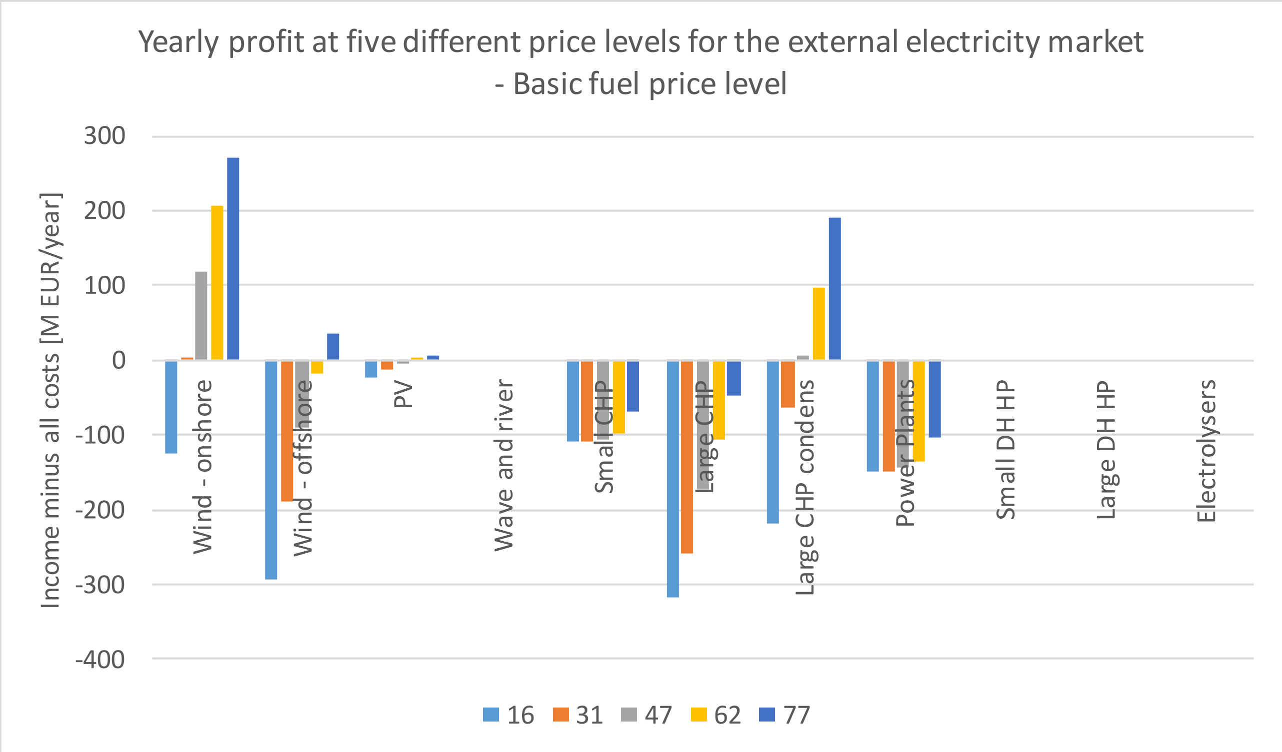

Figure 12 – Yearly profit for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

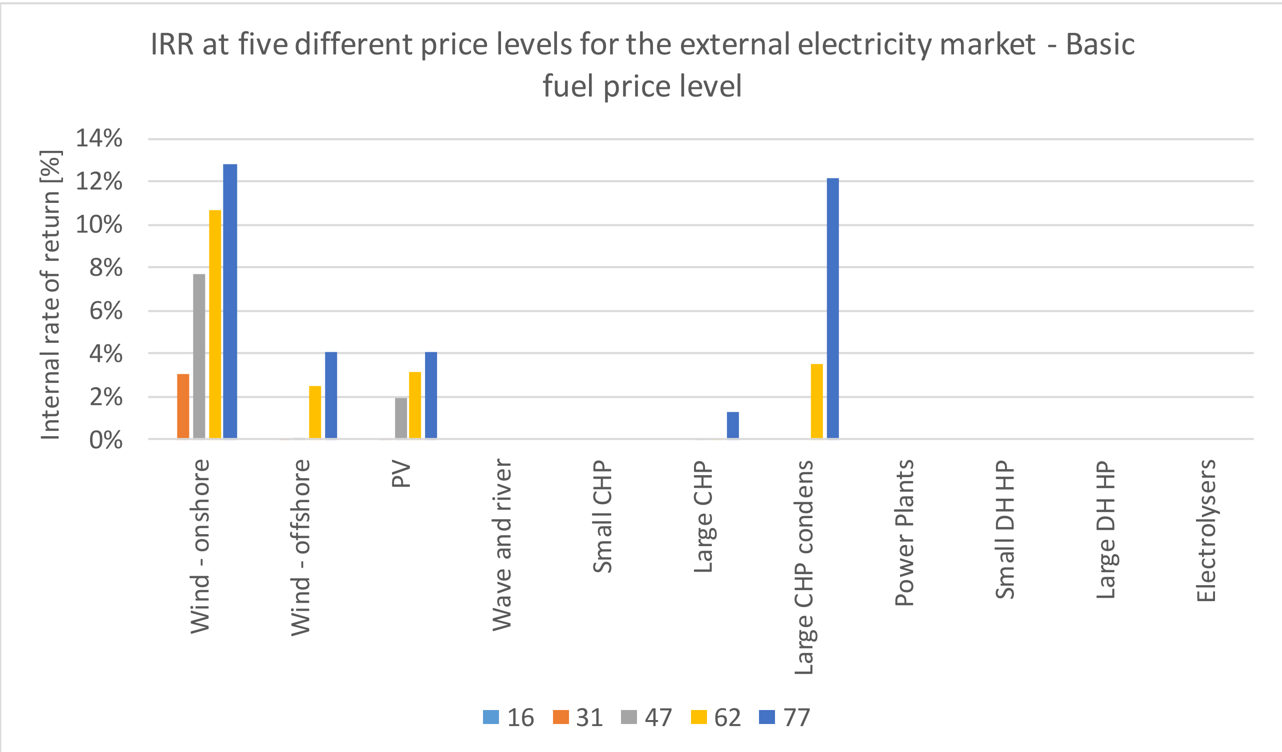

Figure 13 – Internal rate of return for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

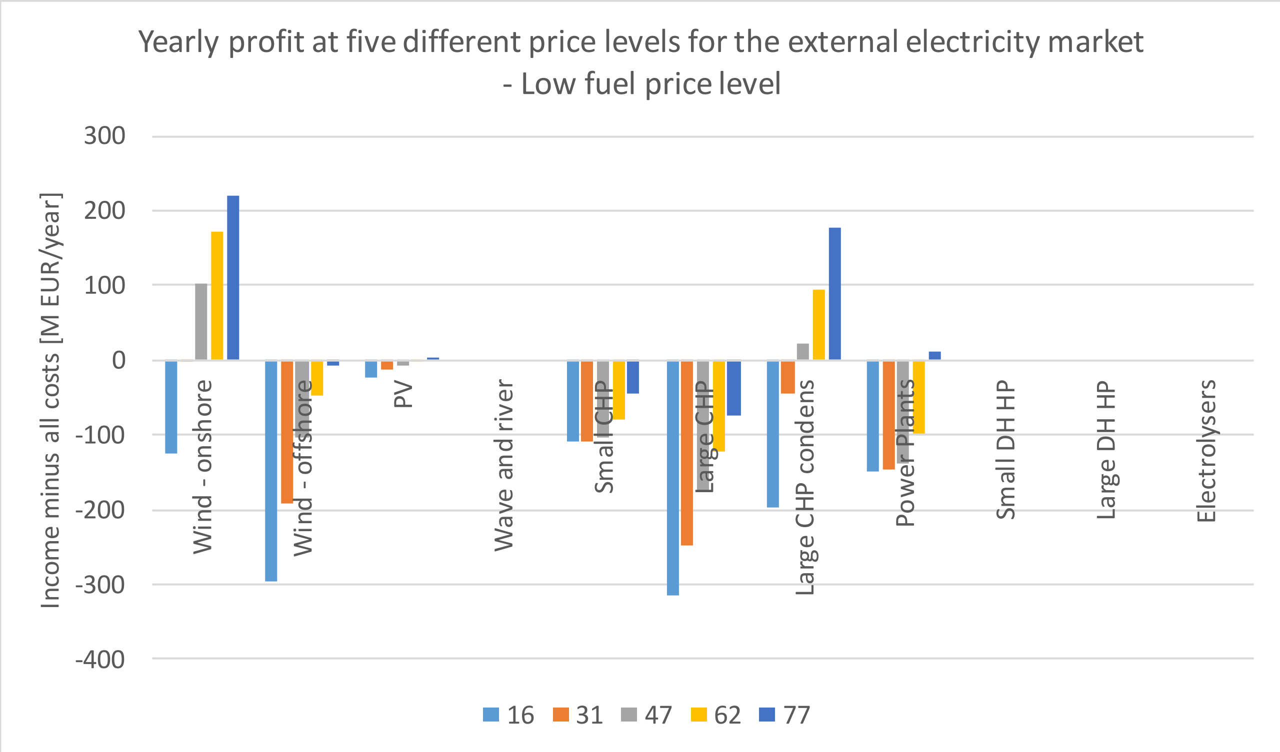

Figure 14 – Yearly profit for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

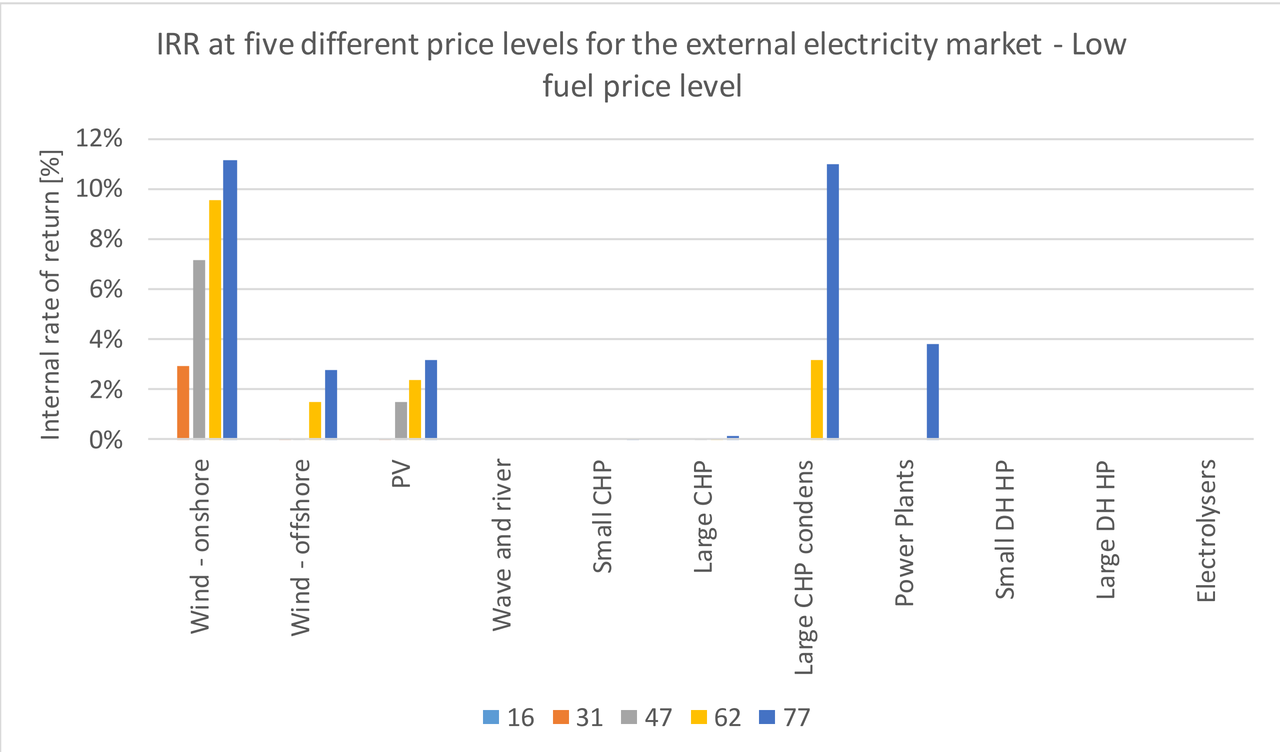

Figure 15 – Internal rate of return for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

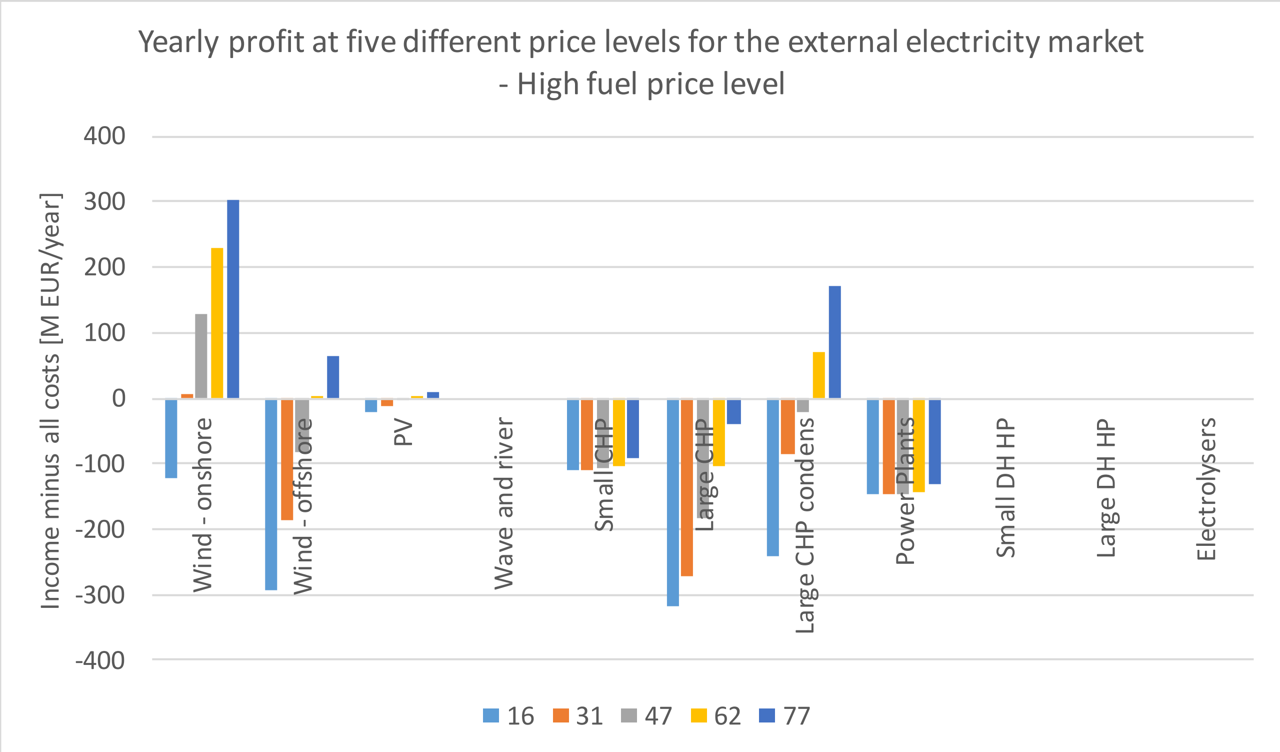

Figure 16 – Yearly profit for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

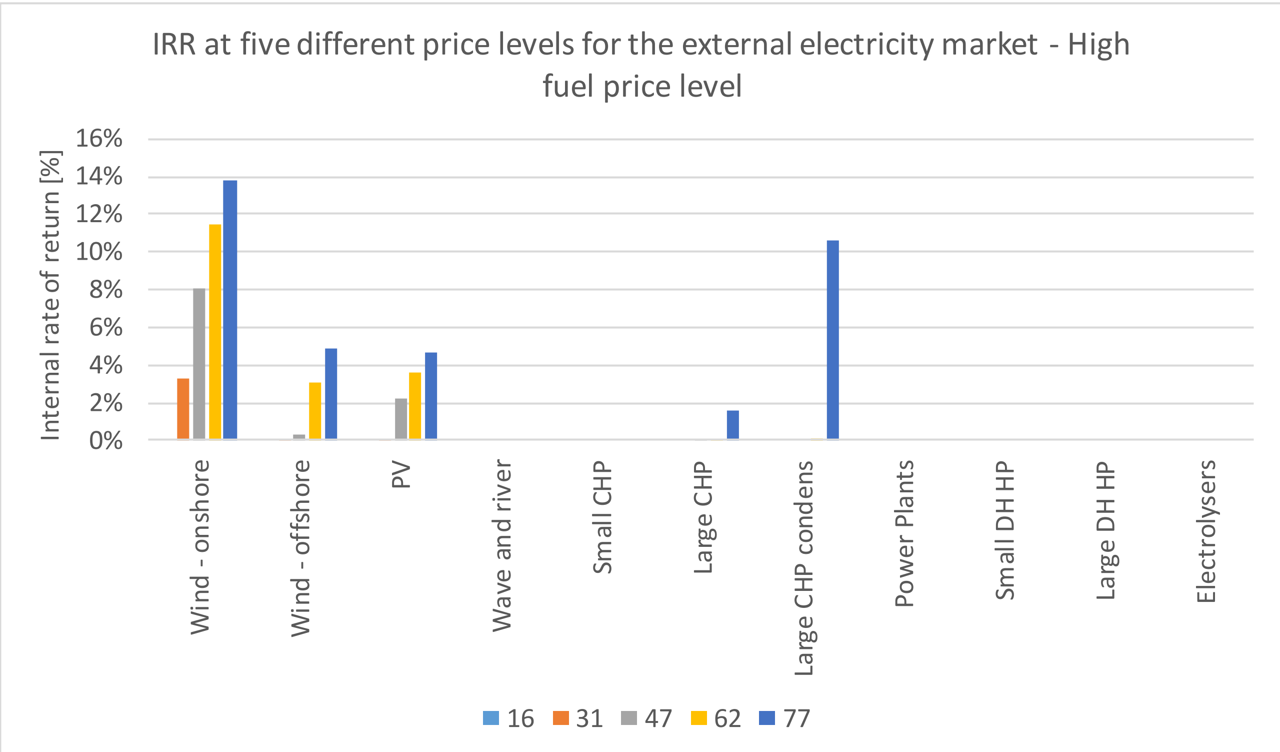

Figure 17 – Internal rate of return for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

4 DEA fossil 2050

4.1 Overview of scenario

Table 6 shows an overview of the main technical and economic characteristic of the electricity producing and main electricity consuming units in the scenario.

General data for units							
	Electric capacity	Electric efficiency	Thermal capacity	Thermal efficiency	Total investment	Annualised investment	Annual fixed O&M
	[MW]	*[%]*	*[MW]*	*[%]*	*[M EUR]*	*[M EUR/a]*	*[M EUR/a]*
Electricity producing units							
Wind - onshore	3500	-	-	-	3150	161	91
Wind - offshore	5000	-	-	-	10600	541	341
PV	800	-	-	-	552	24	6
Wave and river	0	-	-	-	0	0	0
Small CHP	1424	49%	1250	43%	2691	116	88
Large CHP (excl. Condensing)	1568	46%	1500	44%	1364	73	55
- Large CHP condensing operatio	*1575*	*53%*	-	-	*6*	*0*	*0*
Power plants	1400	46%	-	-	1106	64	42
Flexible electricity consumption units							
Small DH HP	0	-	-	-	0	0	0
Large DH HP	0	-	-	-	0	0	0
Electrolysers	0	-	-	-	0	0	0

Table 6 – Overview of relevant units' capacities, efficiencies, investment costs, and annual fixed operation and maintenance (O&M)

For "Electrolysers", only the actual electrolysers are included, meaning that e.g. H2 storage and units used for gasification are not included. For "Large CHP (excl. Condensing)", the capacities and efficiencies are only for CHP operation. "Large CHP condensing operation" is the full condensing capacity of the large CHP units, where the investment and fixed O&M costs cover the difference between the electric capacity in CHP operation and the condensing electric capacity.

Figure 18 shows the yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh).

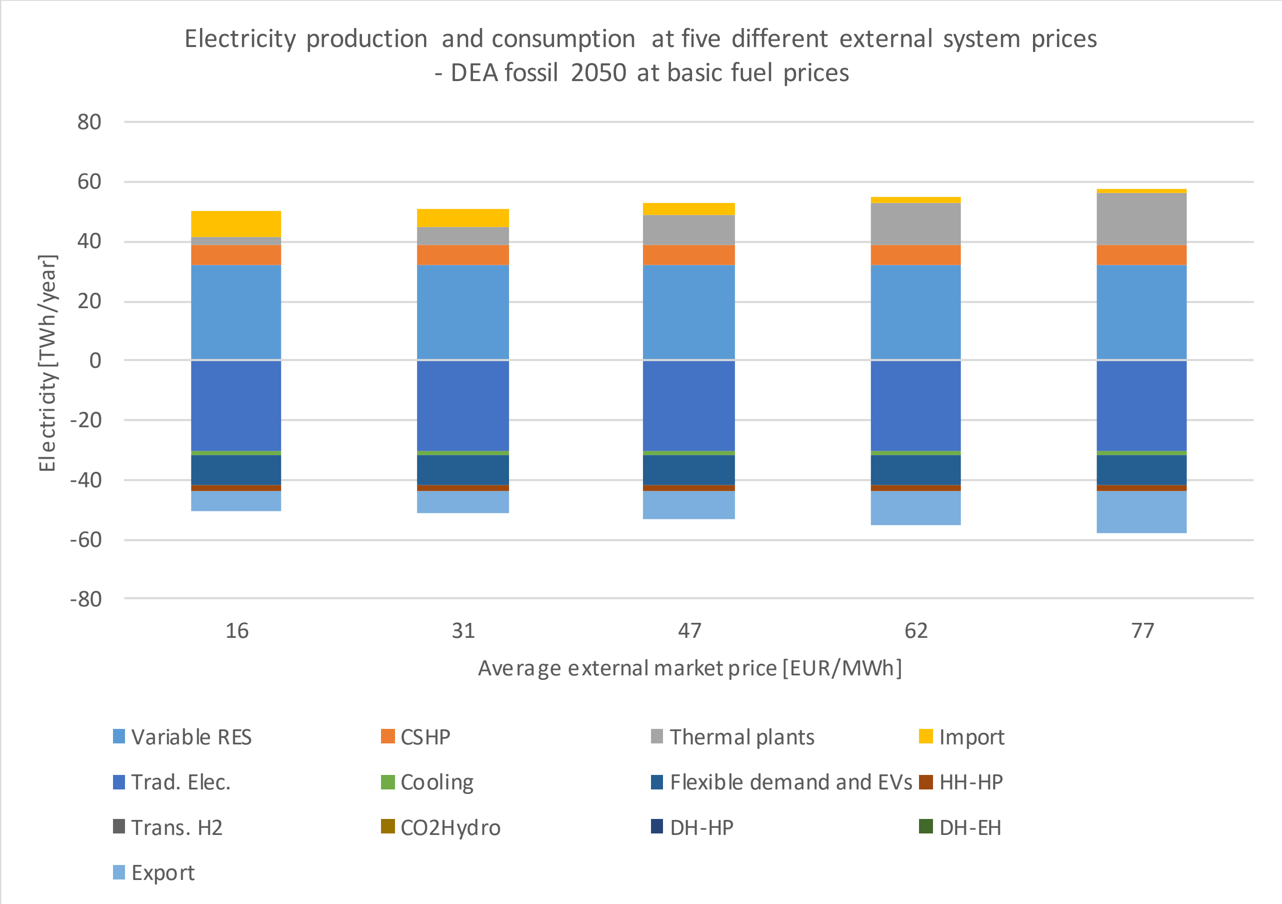

Figure 18 - Yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). RES: Renewable Energy Sources, CSHP: Industrial Combined Heat & Power (incl. waste incineration), HH: Households, HP: Heat Pumps, EV: Electric Vehicle, DH: District Heating, EH: Electric Heating.

4.2 Duration curves for electricity consumption and production

The duration curves shown in this section are only for the average external electricity market price of 77 EUR/MWh.

Figure 19 show the duration curves for different types of residual electricity demands. Residual electricity demand is here understood as the electricity demand minus the variable RES electricity production in any given hour. "Residual hourly fixed" are demands that are fixed on an hourly basis (includes e.g. traditional electricity demands). "Residual hourly and yearly fixed" are both the "Residual hourly fixed" as well as any electricity demands that are fixed on a yearly basis (includes e.g. flexible charged electric vehicles). "All residual" are all residual electricity demands (includes e.g. heat pumps in district heating). Figure 20 show the electricity production duration curves for CSHP, variable RES, and thermal plants.

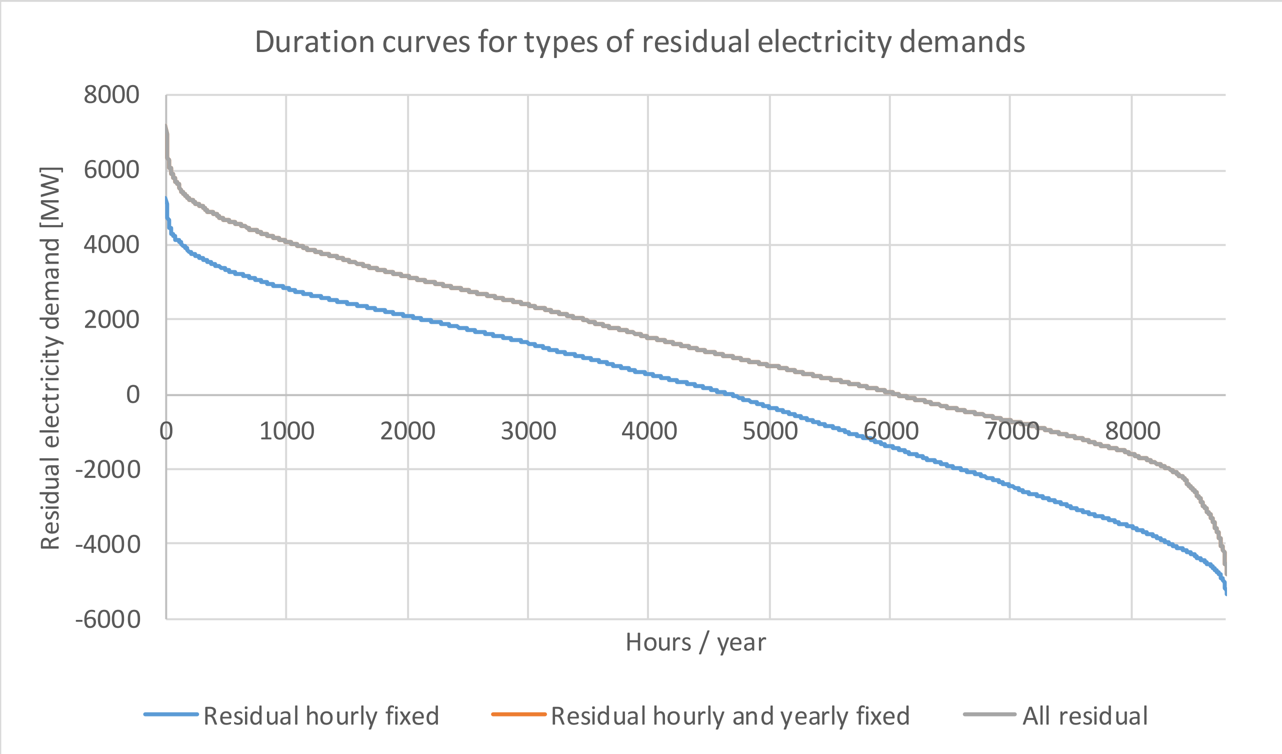

Figure 19 – Duration curves for different types of residual electricity demands at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

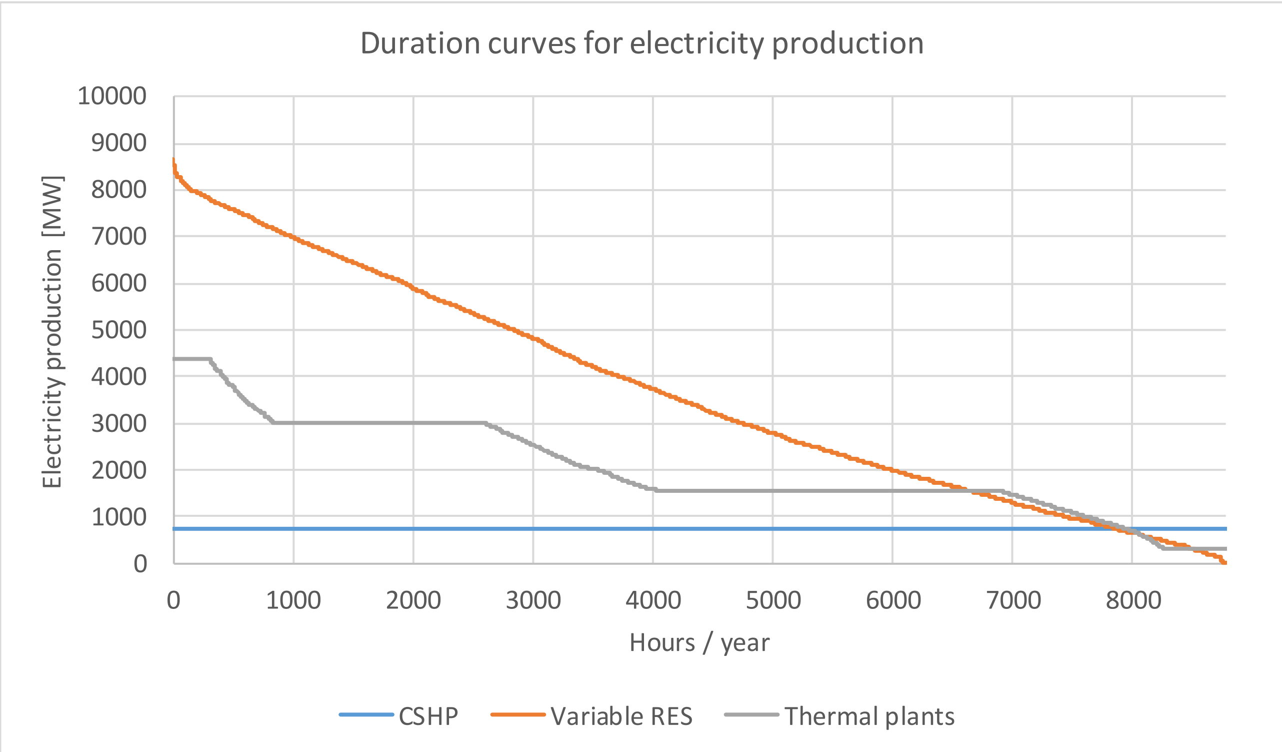

Figure 20 – Duration curves for electricity production by different unit types at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

4.3 Electricity prices

Figure 21, Figure 22, and Figure 23 show for each of the three fuel price levels the resulting hourly electricity market system price using five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). Table 7, Table 8, and Table 9 show the corresponding resulting average, minimum, and maximum electricity price in the simulation.

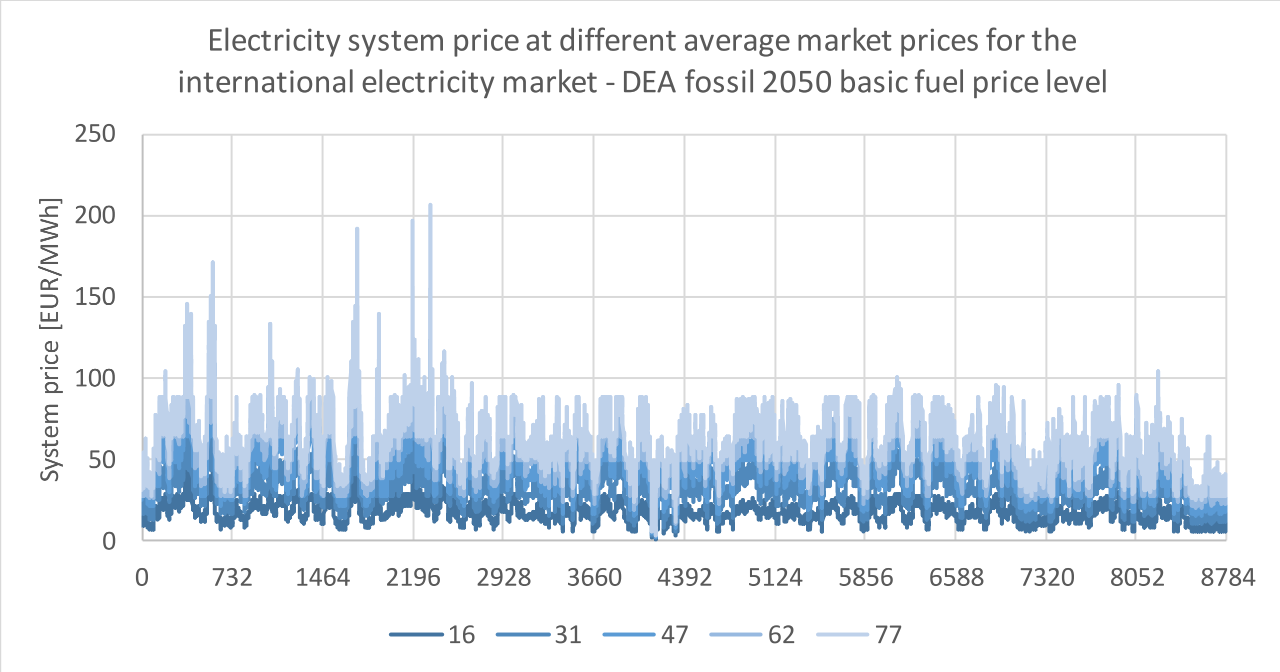

Figure 21 – Hourly system price on Nord Pool Spot at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	17	31	43	53	62
Resulting min	1	2	2	3	3
Resulting max	57	88	124	157	206

Table 7 - Resulting yearly average, minimum and maximum electricity prices at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

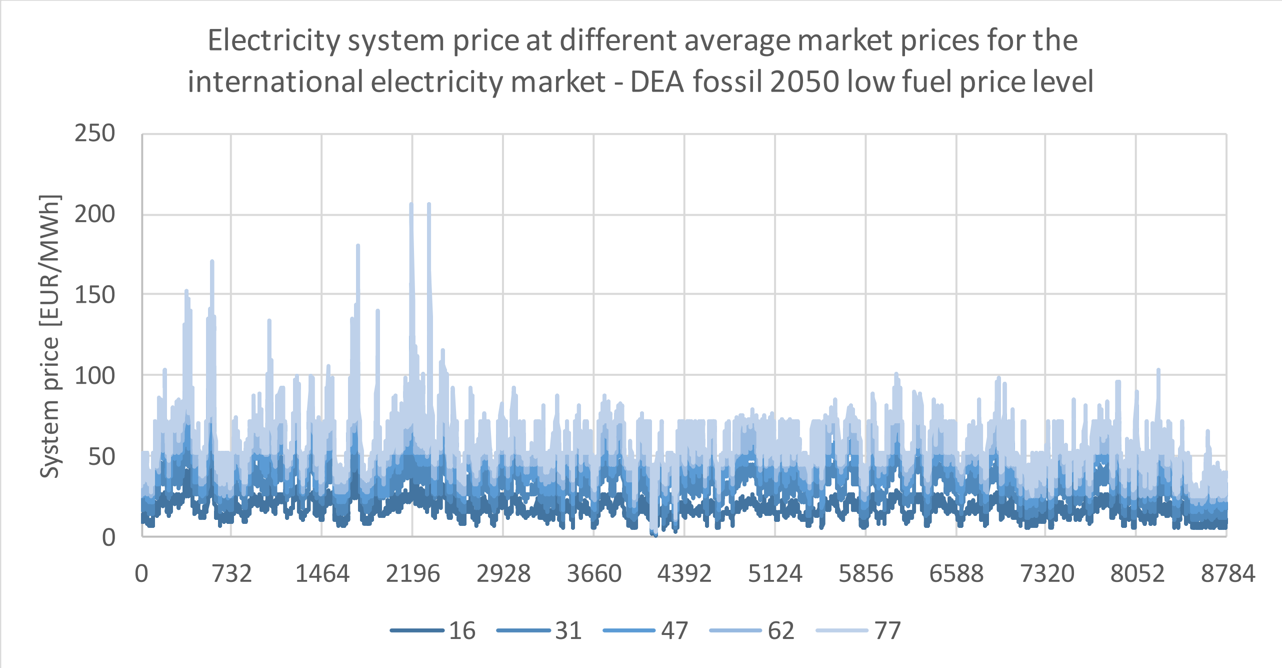

Figure 22 – Hourly system price on Nord Pool Spot at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	17	31	41	50	58
Resulting min	1	2	2	3	3
Resulting max	52	83	124	165	206

Table 8 - Resulting yearly average, minimum and maximum electricity prices at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

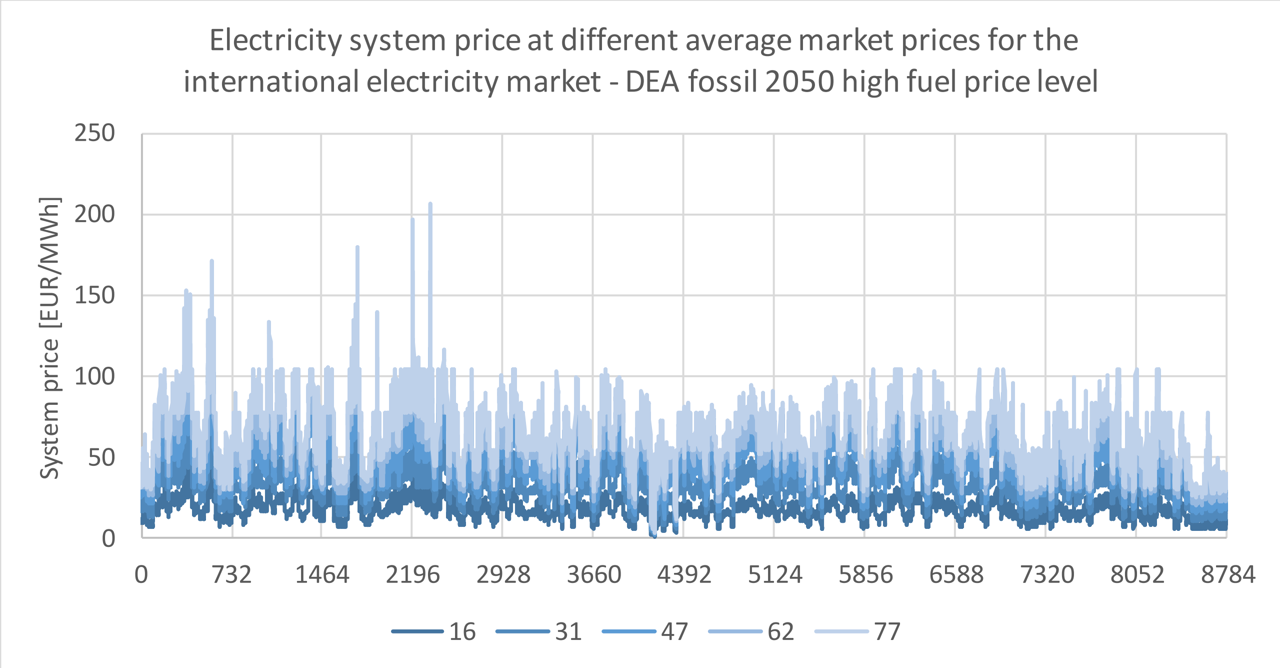

Figure 23 – Hourly system price on Nord Pool Spot at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	17	31	44	55	65
Resulting min	1	2	2	3	3
Resulting max	57	98	118	165	207

Table 9 - Resulting yearly average, minimum and maximum electricity prices at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

4.4 Marginal activated unit

The purpose of this section is to identify the marginal activated unit in the simulated energy system. This is done by first separating the array for the electricity market price into arrays with the marginal price of each unit being the lower limit of an array and the next marginal most expensive unit being the upper limit. E.g. “Incr. B2 decr. EB2” has a marginal price of 38 and the next least expensive unit is “Incr. CHP2 decr. B2” with a marginal price of 67, resulting in the “Incr. B2 decr. EB2” array being prices between 38 and 67. After the arrays have been established, it is for each hour checked whether the activated technology was in fact in use or not. If not, then if there is variable RES in operation this becomes the marginal activated unit. If there is no variable RES in operation, then it that hour is added to the “Rest” category (i.e. the external market is the marginal “unit”). This approach only account for the units activated within the simulated energy system and does not account for what units are activated outside of the simulated energy system in case of import and export of electricity.

This is done for each of the three fuel price levels, as well as the five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). See Figure 24, Figure 25, and Figure 26.

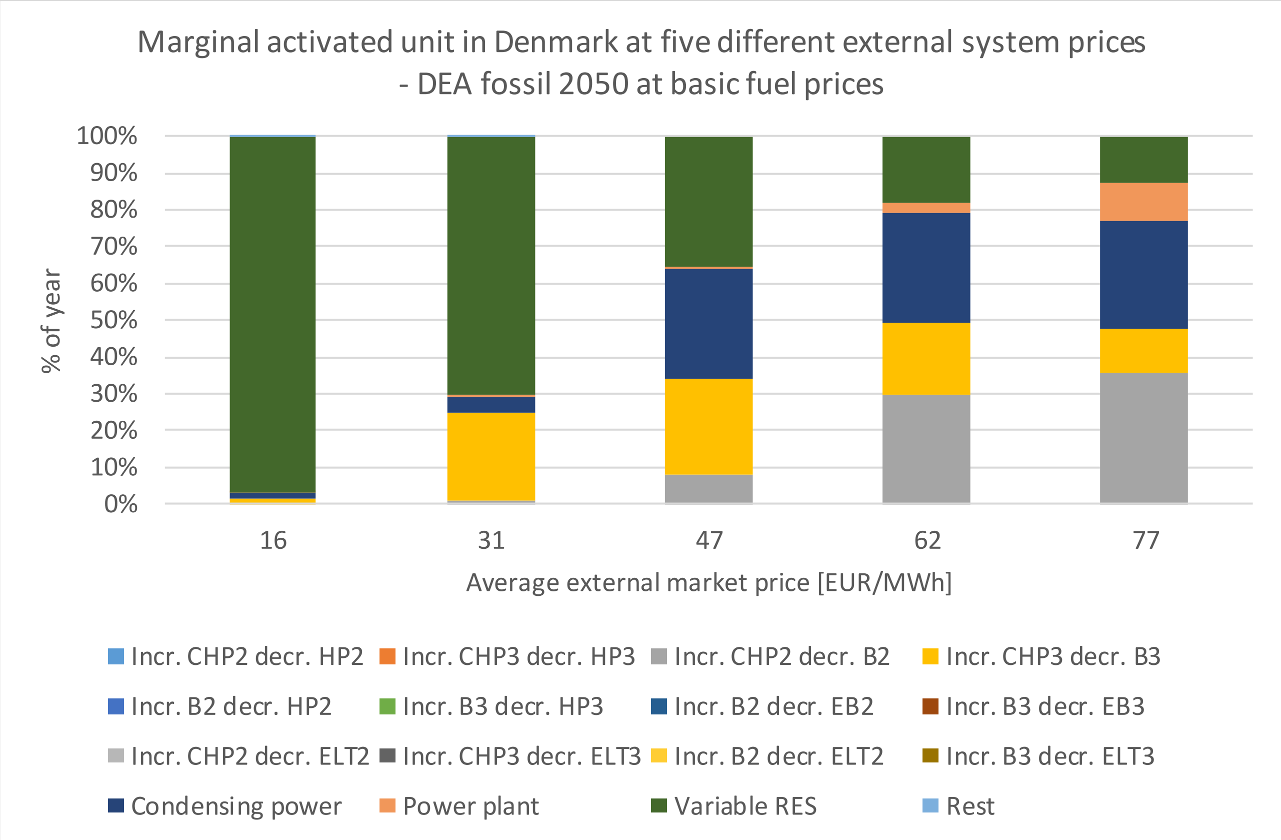

Figure 24 – Marginal activated unit in Denmark at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

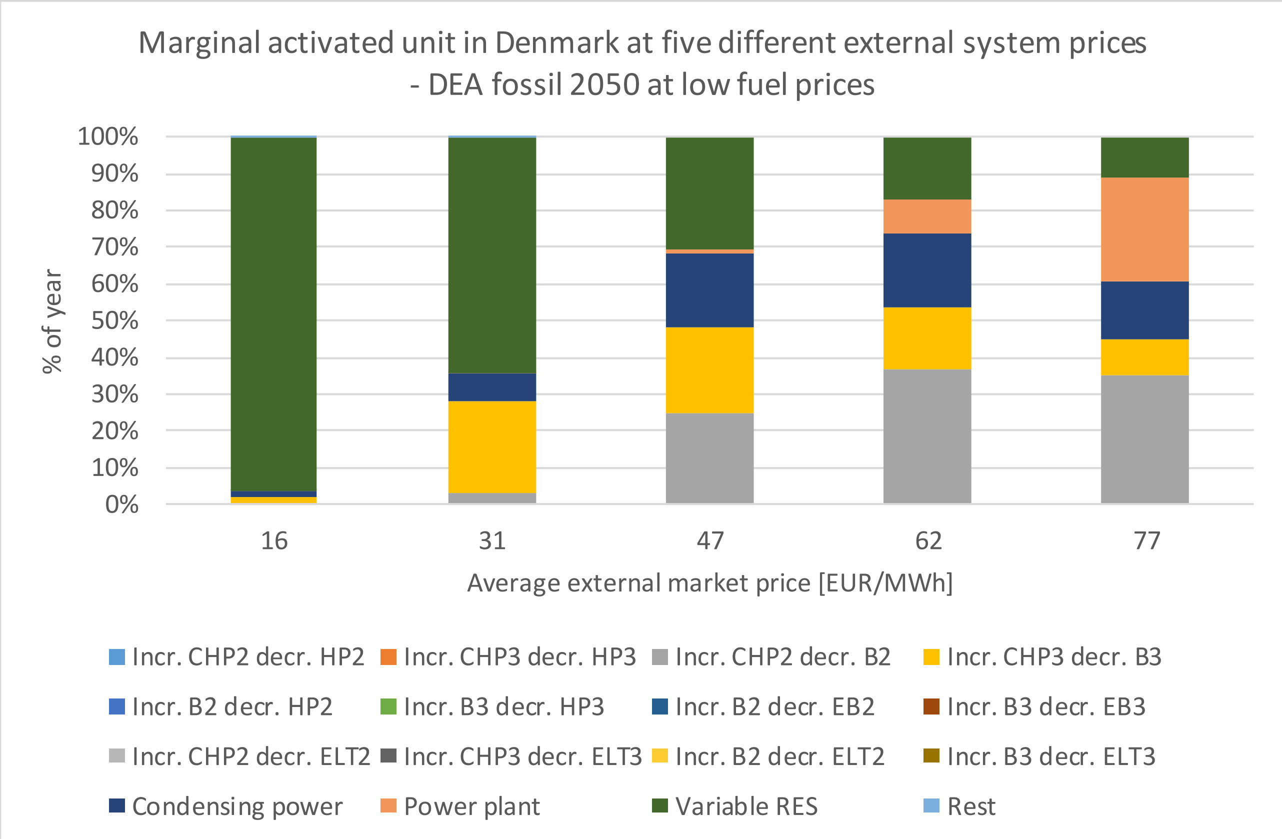

Figure 25 – Marginal activated unit in Denmark at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

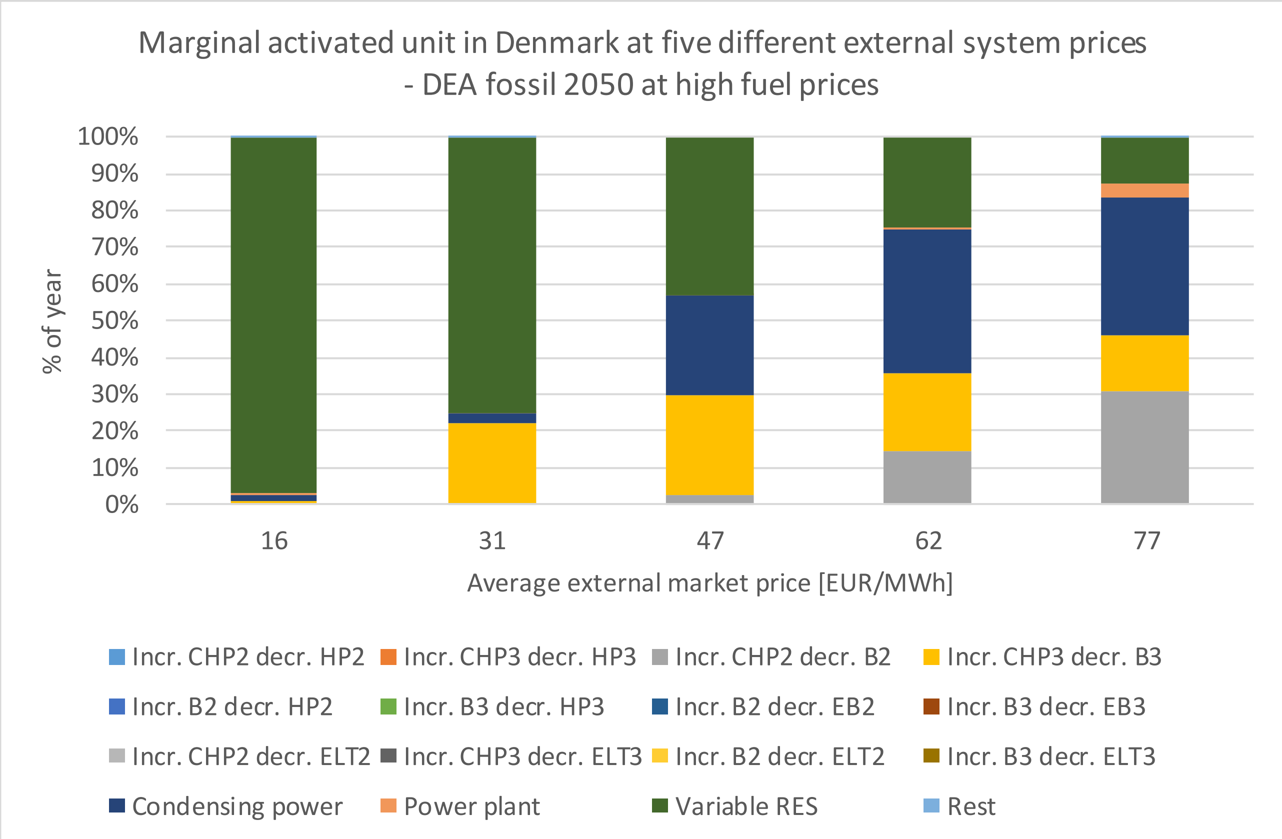

Figure 26 – Marginal activated unit in Denmark at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

4.5 Profit analysis

The aim of this analysis is to identify which types of units are expected to be able to cover their own costs in the current Nord Pool Spot regime. Only costs directly related to the specific units are included (investment, fixed operational and maintenance (O&M), variable O&M, fuel costs, and CO_2-costs). As such, potential related costs, e.g. grid costs and storage costs, are not included. For the income, only sale of electricity on Nord Pool Spot (as modelled in EnergyPLAN) and sale of produced district heating are included. For sale of district heating, it is assumed that the value of the produced heat is equal to the short-marginal cost of an average fuel boiler in the corresponding district heating group.

Figure 27, Figure 29, and Figure 31 show the yearly profit of each unit type where a discount rate of 3% has been used. Figure 28, Figure 30, and Figure 32 show the corresponding internal rate of return (IRR), with only incomes being sale of electricity on Nord Pool Spot and sale of heat for district heating. Each figure represents a different fuel price level.

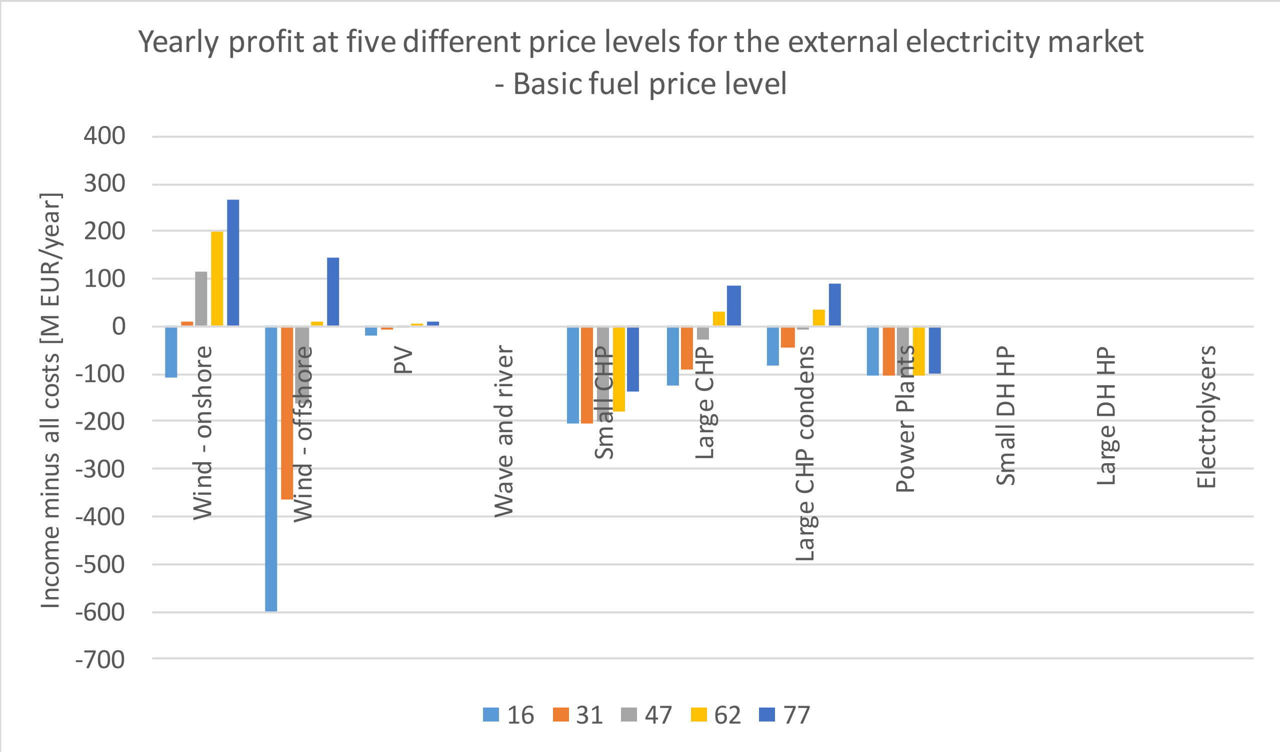

Figure 27 – Yearly profit for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

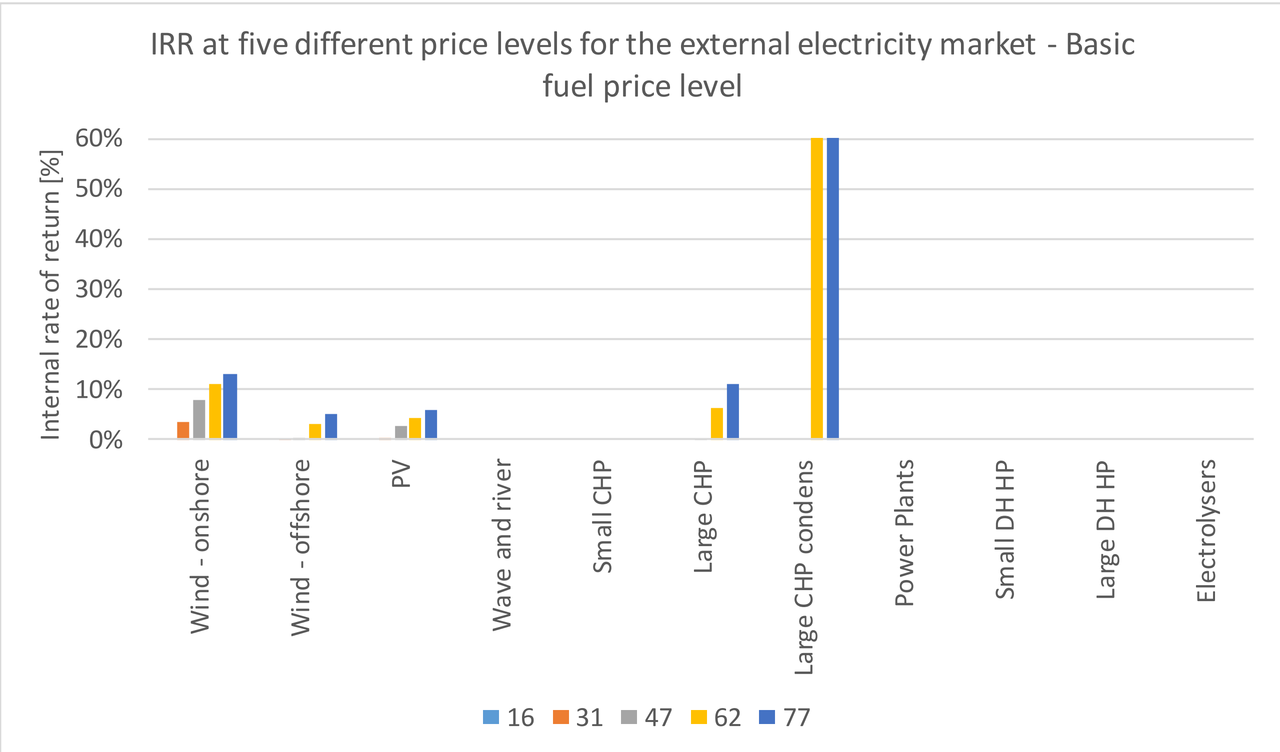

Figure 28 – Internal rate of return for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

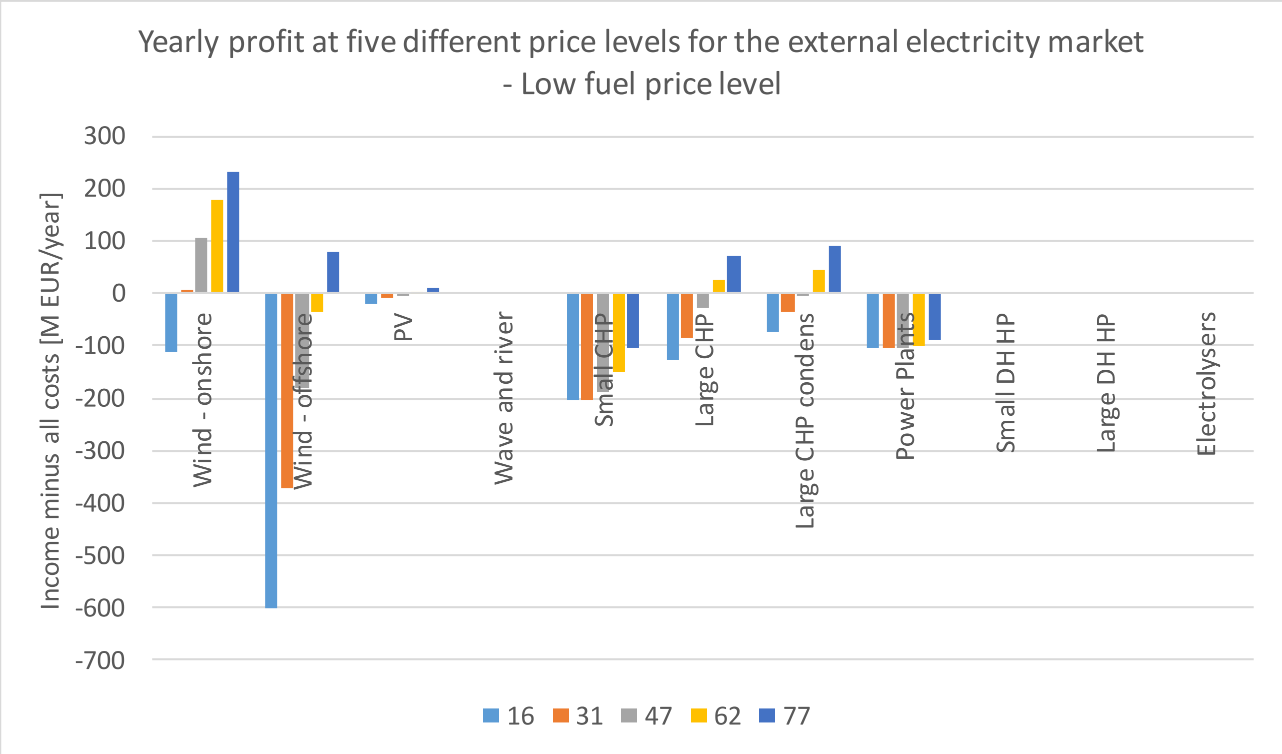

Figure 29 – Yearly profit for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

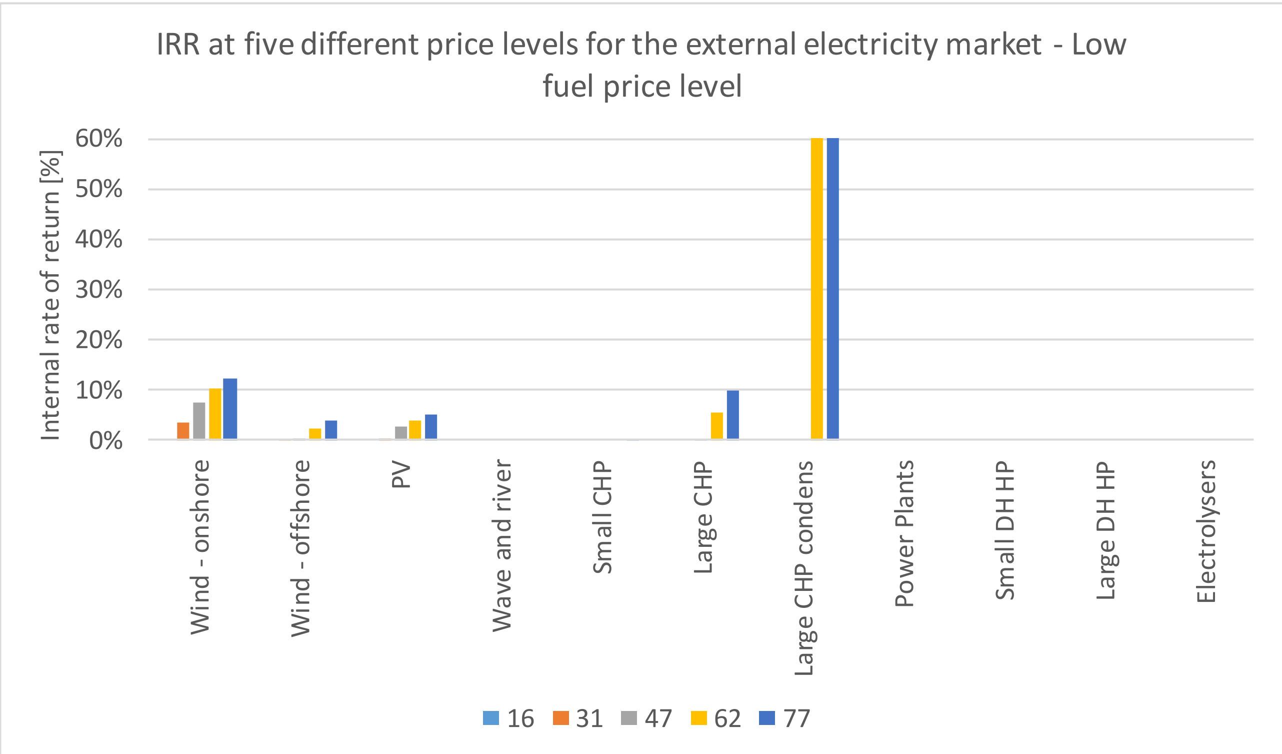

Figure 30 – Internal rate of return for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

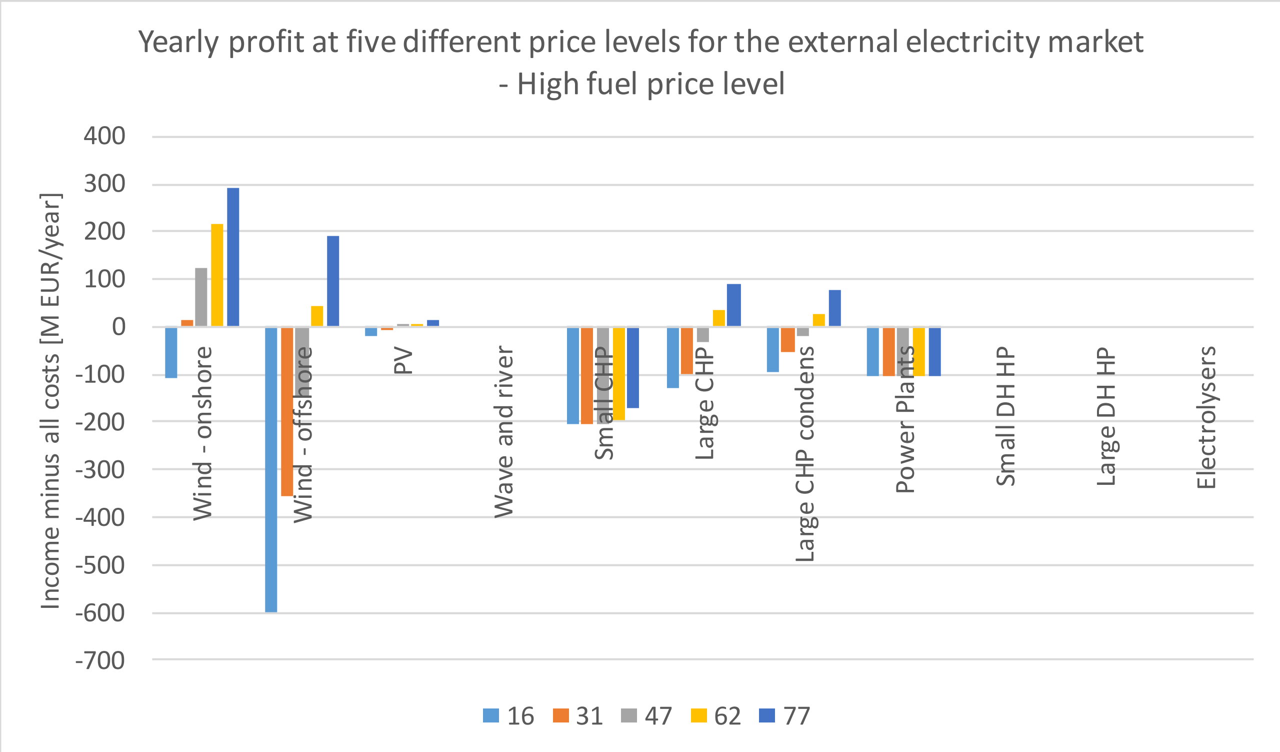

Figure 31 – Yearly profit for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

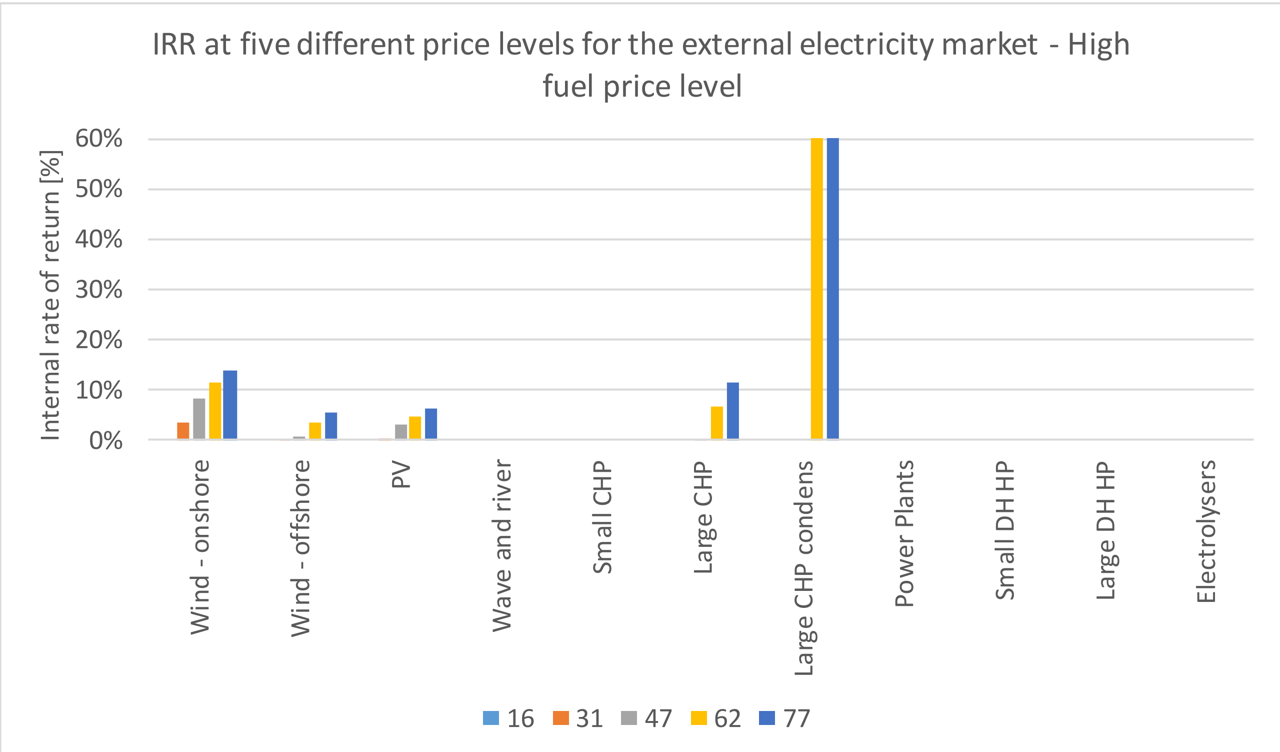

Figure 32 – Internal rate of return for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

5 DEA wind 2035

5.1 Overview of scenario

Table 10 shows an overview of the main technical and economic characteristic of the electricity producing and main electricity consuming units in the scenario.

General data for units							
	Electric capacity	Electric efficiency	Thermal capacity	Thermal efficiency	Total investment	Annualised investment	Annual fixed O&M
	[MW]	*[%]*	*[MW]*	*[%]*	*[M EUR]*	*[M EUR/a]*	*[M EUR/a]*
Electricity producing units							
Wind - onshore	3500	-	-	-	3500	201	91
Wind - offshore	5000	-	-	-	12150	698	316
PV	1000	-	-	-	820	35	8
Wave and river	0	-	-	-	0	0	0
Small CHP	1026	49%	900	43%	1108	59	39
Large CHP (excl. Condensing)	926,37	38%	1268	52%	1843	80	57
- Large CHP condensing operatio	*1421*	*44%*	-	-	*574*	*30*	*20*
Power plants	900	46%	-	-	1044	54	37
Flexible electricity consumption units							
Small DH HP	133	-	399	300%	456	26	9
Large DH HP	83	-	249	300%	270	15	5
Electrolysers	1634 -	-	-		1422	76	57

Table 10 – Overview of relevant units' capacities, efficiencies, investment costs, and annual fixed operation and maintenance (O&M)

For "Electrolysers", only the actual electrolysers are included, meaning that e.g. H2 storage is not included. For "Large CHP (excl. Condensing)", the capacities and efficiencies are only for CHP operation. "Large CHP condensing operation" is the full condensing capacity of the large CHP units, where the investment and fixed O&M costs cover the difference between the electric capacity in CHP operation and the condensing electric capacity.

Figure 33 shows the yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh).

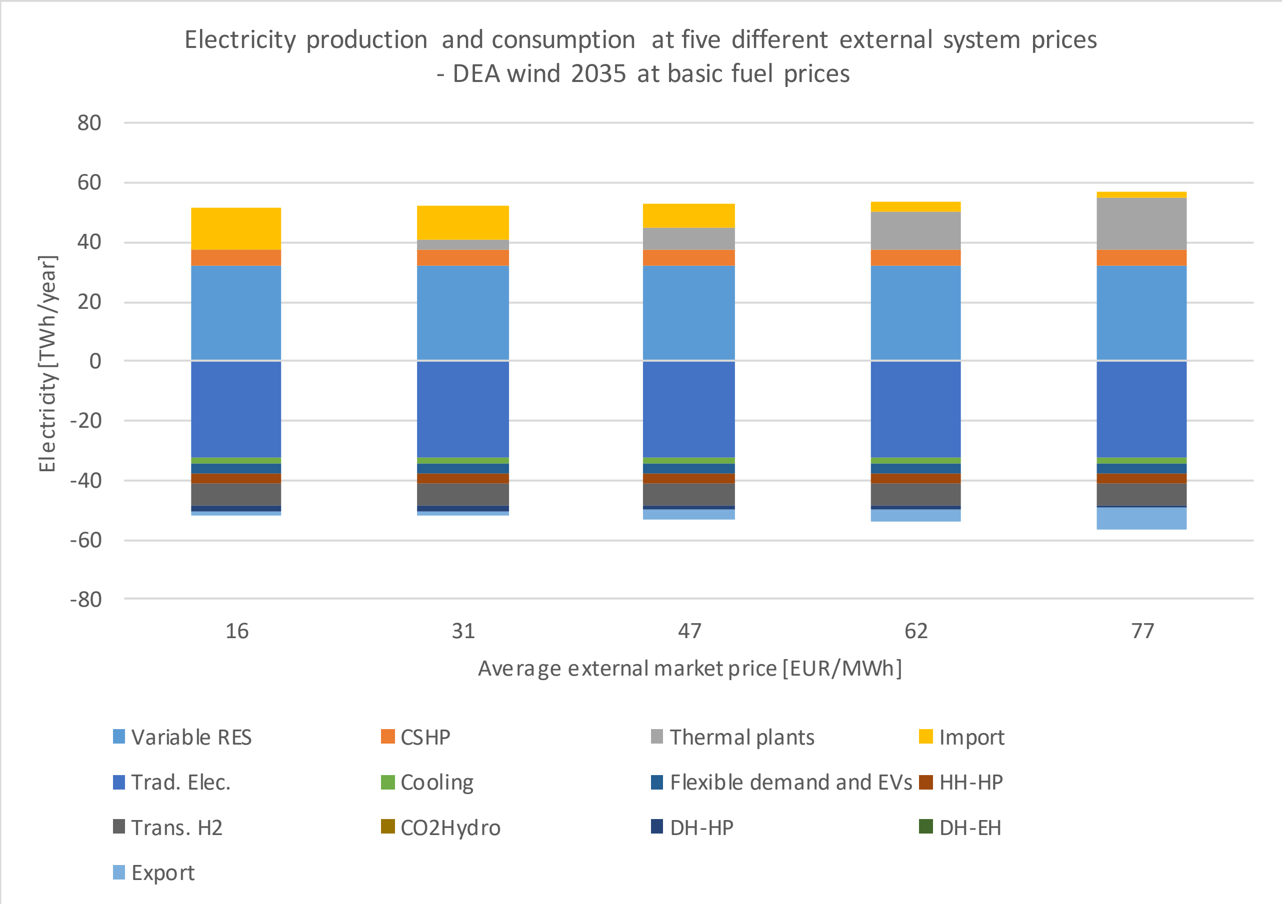

Figure 33 - Yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). RES: Renewable Energy Sources, CSHP: Industrial Combined Heat & Power (incl. waste incineration), HH: Households, HP: Heat Pumps, EV: Electric Vehicle, DH: District Heating, EH: Electric Heating.

5.2 Duration curves for electricity consumption and production

The duration curves shown in this section are only for the average external electricity market price of 77 EUR/MWh.

Figure 34 show the duration curves for different types of residual electricity demands. Residual electricity demand is here understood as the electricity demand minus the variable RES electricity production in any given hour. “Residual hourly fixed” are demands that are fixed on an hourly basis (includes e.g. traditional electricity demands). “Residual hourly and yearly fixed” are both the “Residual hourly fixed” as well as any electricity demands that are fixed on a yearly basis (includes e.g. flexible charged electric vehicles). “All residual” are all residual electricity demands (includes e.g. heat pumps in district heating). Figure 35 show the electricity production duration curves for CSHP, variable RES, and thermal plants.

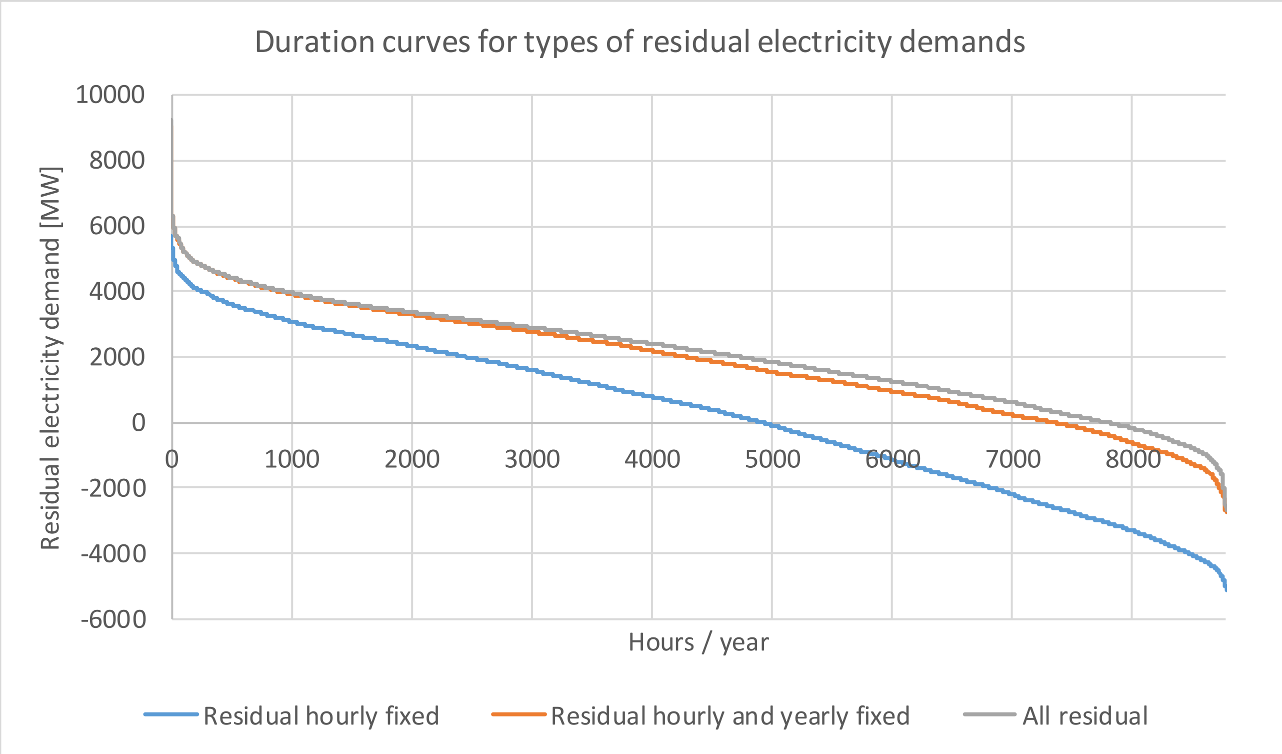

Figure 34 – Duration curves for different types of residual electricity demands at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

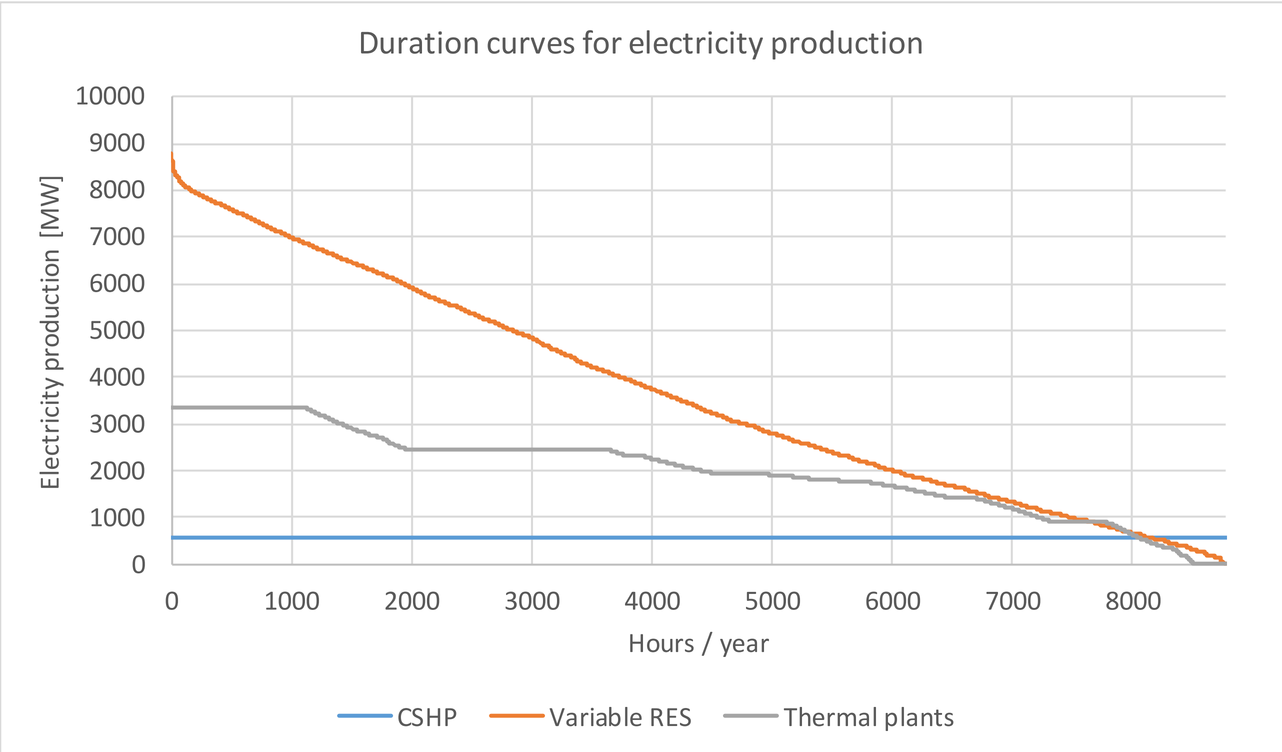

Figure 35 – Duration curves for electricity production by different unit types at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

5.3 Electricity prices

Figure 36, Figure 37, and Figure 38 show for each of the three fuel price levels the resulting hourly electricity market system price using five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). Table 11, Table 12, and Table 13 show the corresponding resulting average, minimum, and maximum electricity price in the simulation.

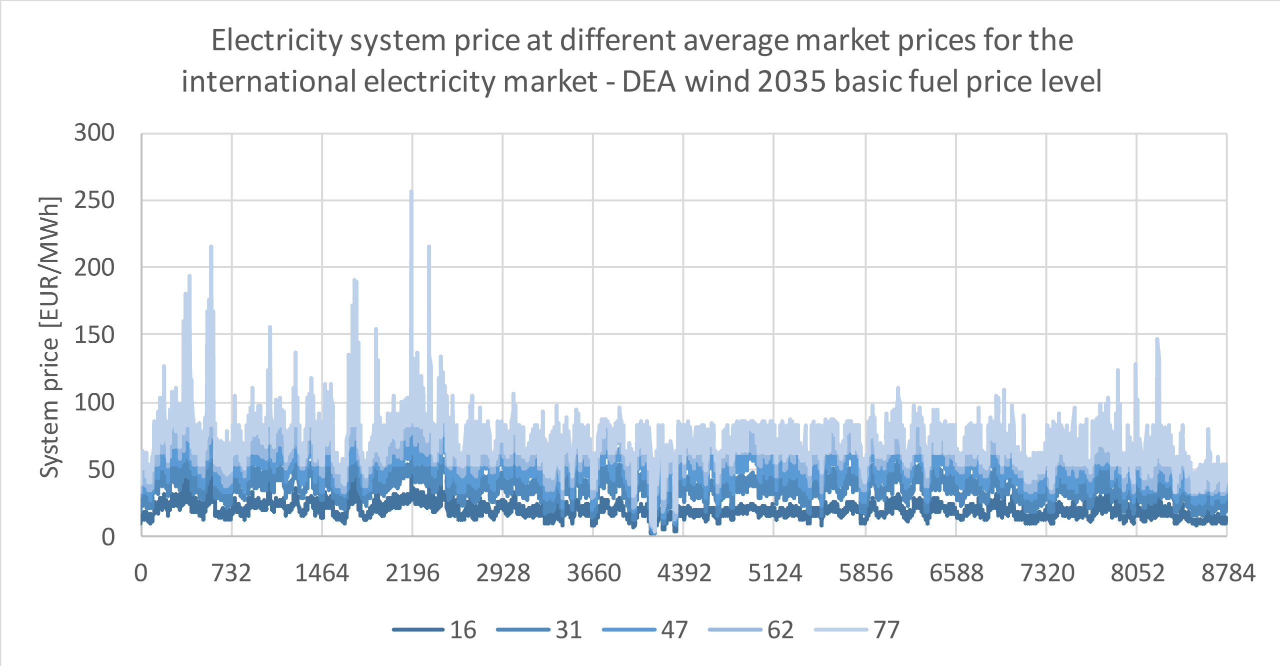

Figure 36 – Hourly system price on Nord Pool Spot at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	20	36	50	61	70
Resulting min	2	2	3	4	4
Resulting max	62	104	155	206	257

Table 11 - Resulting yearly average, minimum and maximum electricity prices at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

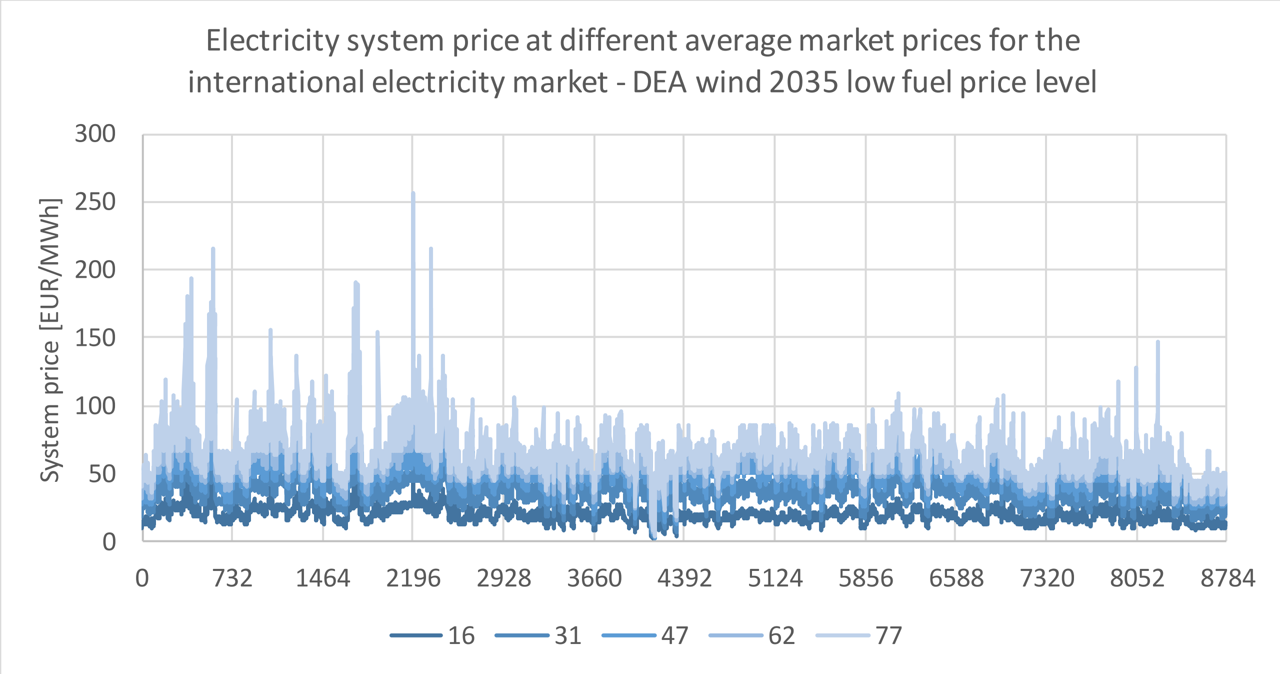

Figure 37 – Hourly system price on Nord Pool Spot at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	19	35	47	56	66
Resulting min	2	2	3	4	4
Resulting max	59	104	155	206	257

Table 12 - Resulting yearly average, minimum and maximum electricity prices at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

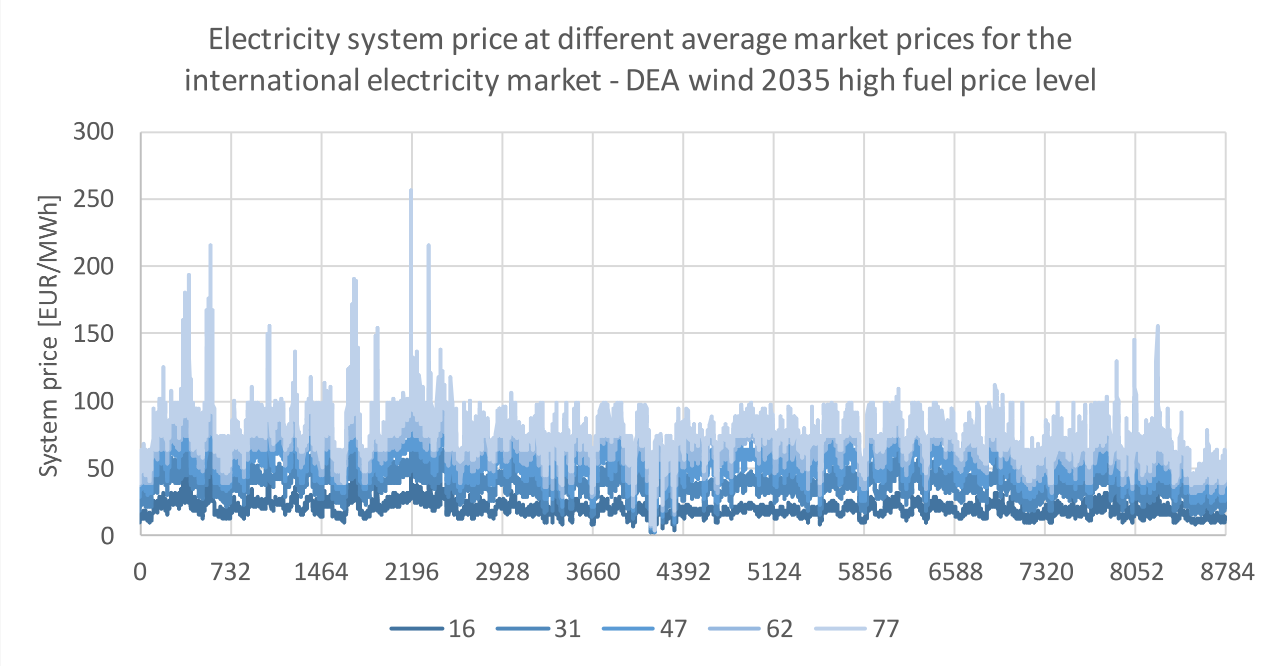

Figure 38 – Hourly system price on Nord Pool Spot at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	20	37	52	64	75
Resulting min	2	2	3	4	4
Resulting max	64	104	155	206	257

Table 13 - Resulting yearly average, minimum and maximum electricity prices at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

5.4 Marginal activated unit

The purpose of this section is to identify the marginal activated unit in the simulated energy system. This is done by first separating the array for the electricity market price into arrays with the marginal price of each unit being the lower limit of an array and the next marginal most expensive unit being the upper limit. E.g. “Incr. B2 decr. EB2” has a marginal price of 38 and the next least expensive unit is “Incr. CHP2 decr. B2” with a marginal price of 67, resulting in the “Incr. B2 decr. EB2” array being prices between 38 and 67. After the arrays have been established, it is for each hour checked whether the activated technology was in fact in use or not. If not, then if there is variable RES in operation this becomes the marginal activated unit. If there is no variable RES in operation, then it that hour is added to the “Rest” category (i.e. the external market is the marginal “unit”). This approach only account for the units activated within the simulated energy system and does not account for what units are activated outside of the simulated energy system in case of import and export of electricity.

This is done for each of the three fuel price levels, as well as the five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). See Figure 39, Figure 40, and Figure 41.

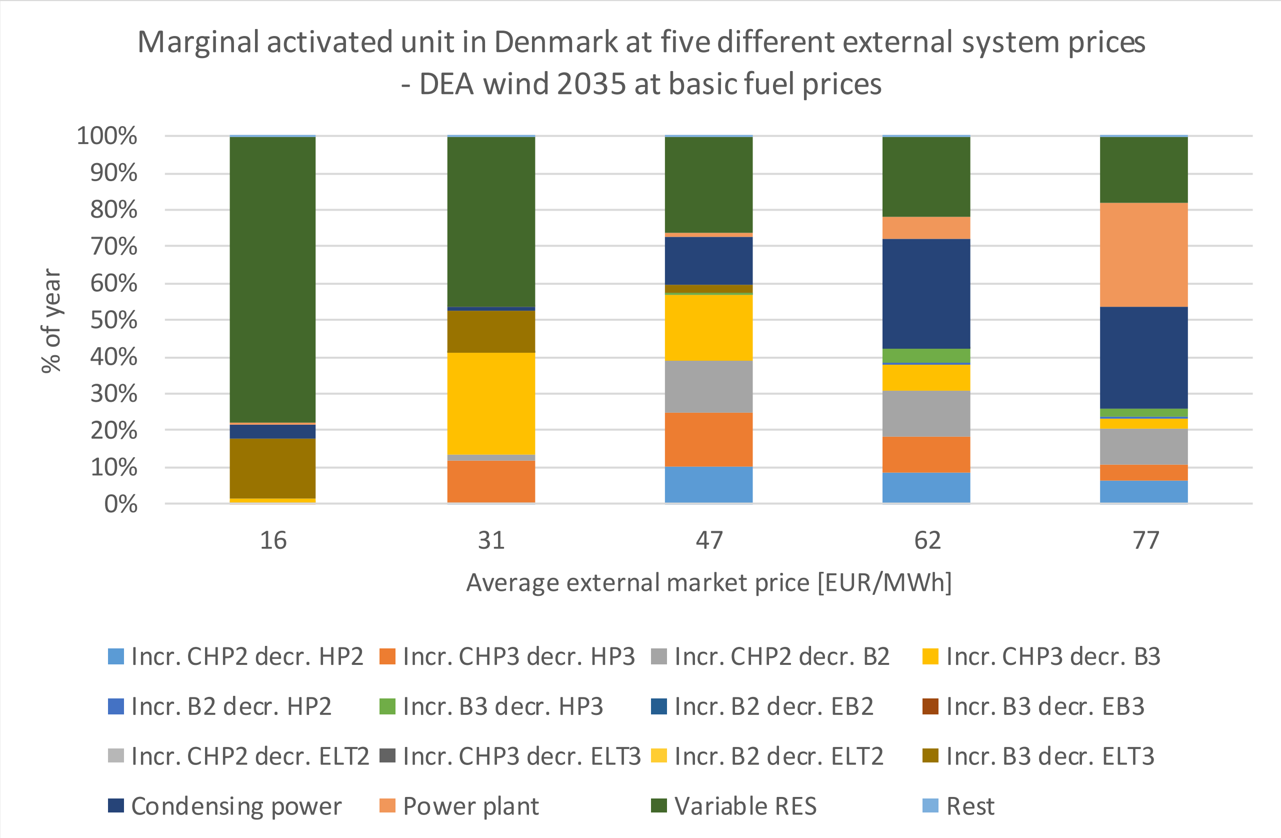

Figure 39 – Marginal activated unit in Denmark at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

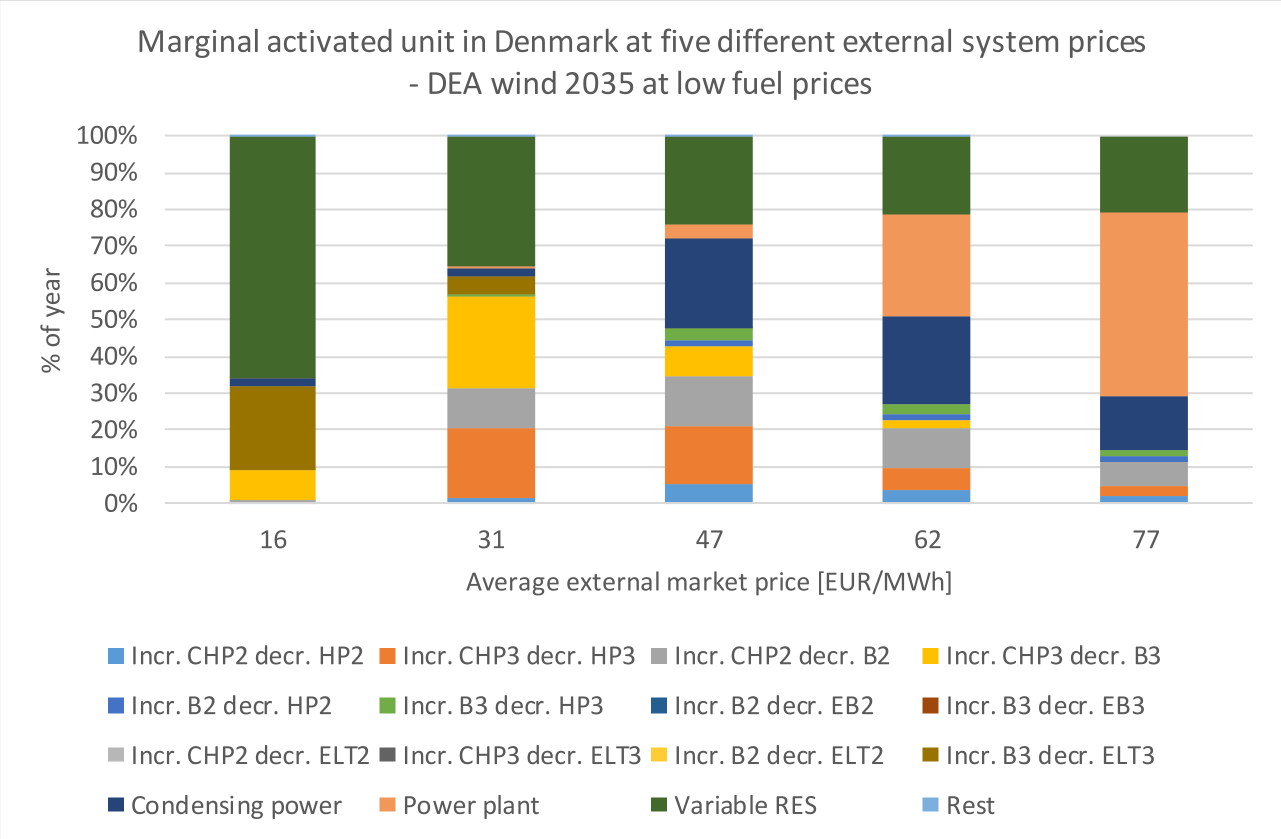

Figure 40 – Marginal activated unit in Denmark at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

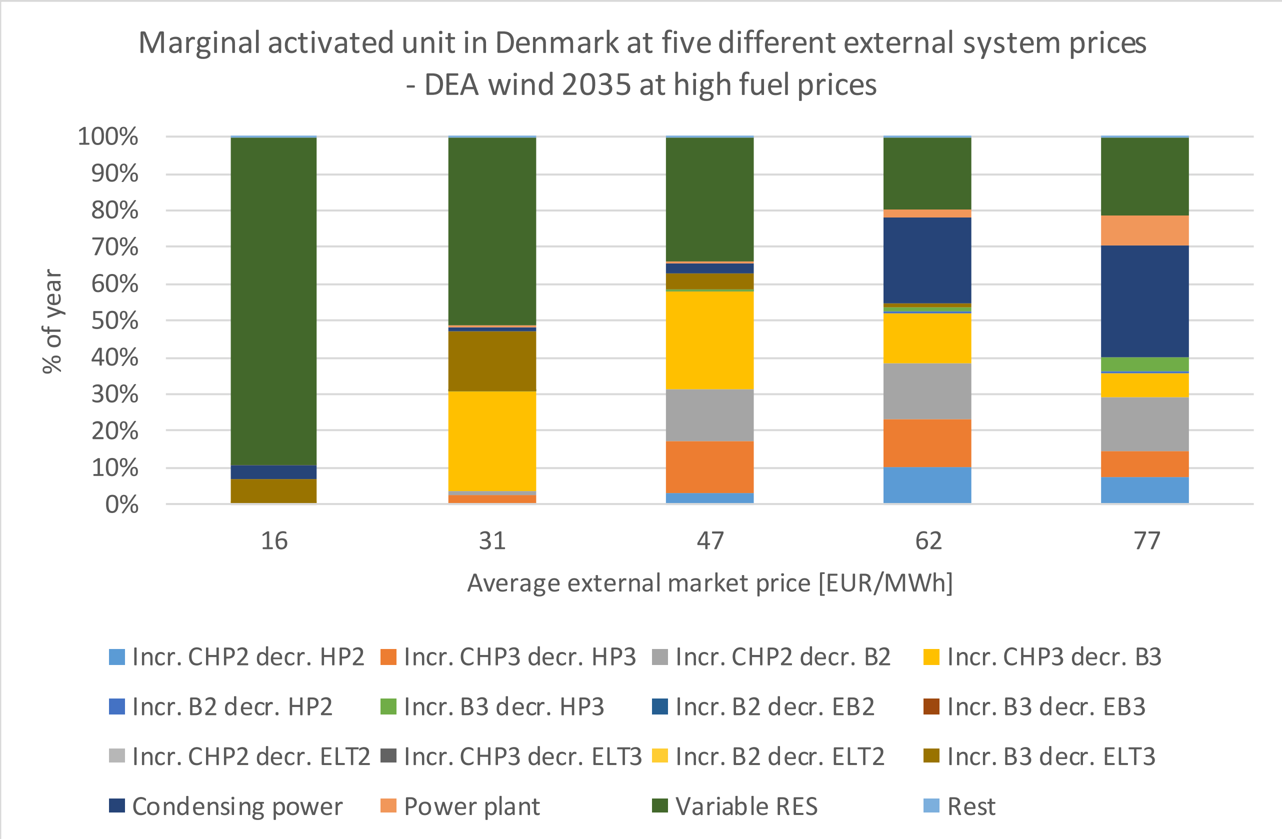

Figure 41 – Marginal activated unit in Denmark at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

5.5 Profit analysis

The aim of this analysis is to identify which types of units are expected to be able to cover their own costs in the current Nord Pool Spot regime. Only costs directly related to the specific units are included (investment, fixed O&M, variable O&M, fuel costs, and CO_2-costs). As such, potential related costs, e.g. grid costs and storage costs, are not included. For the income, only sale of electricity on Nord Pool Spot (as modelled in EnergyPLAN), sale of produced district heating and sale of hydrogen are included. For sale of district heating, it is assumed that the value of the produced heat is equal to the short-marginal cost of an average fuel boiler in the corresponding district heating group.

Figure 42, Figure 44, and Figure 46 show the yearly profit of each unit type where a discount rate of 3% has been used. Figure 43, Figure 45, and Figure 47 show the corresponding internal rate of return (IRR). The only incomes being sale of electricity on Nord Pool Spot, sale of heat for district heating, and sale of hydrogen. In these figures, the sale of hydrogen is simply assumed to equal the natural gas price. Figure 48 shows what the lowest value for the produced hydrogen should be to make the electrolysers feasible. Each figure represents a different fuel price level.

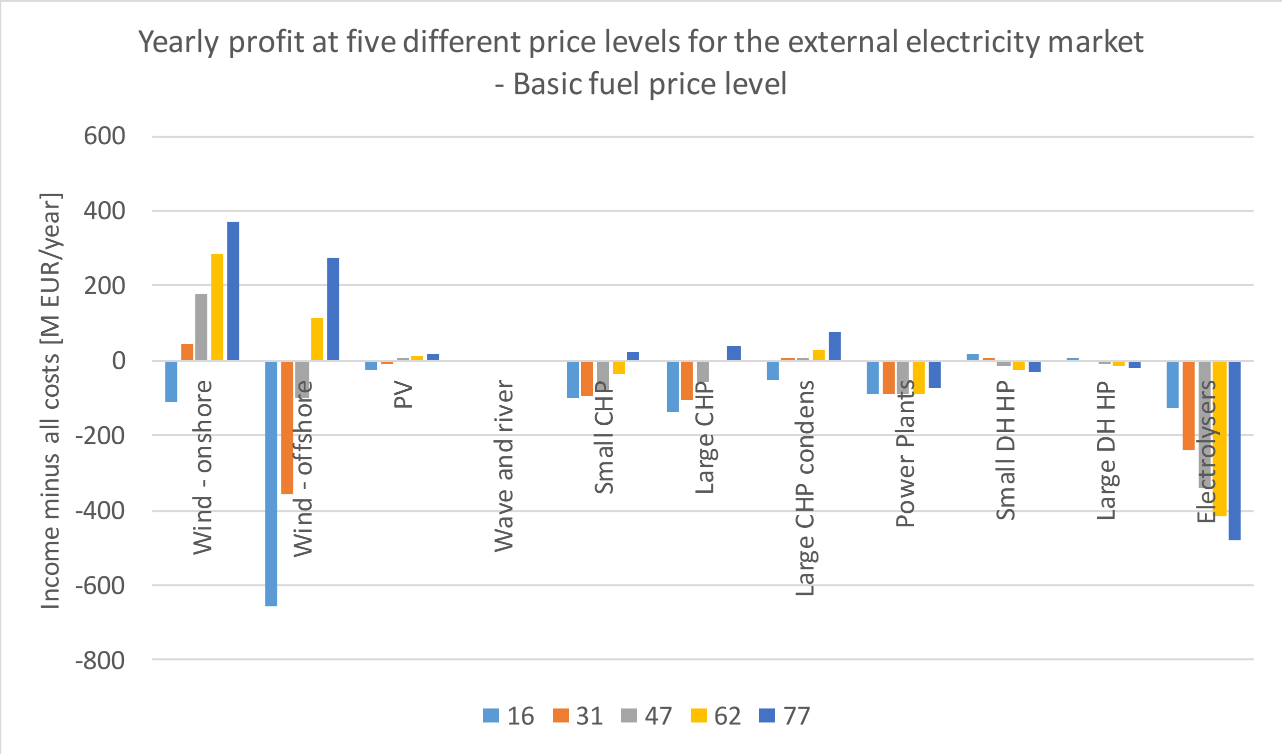

Figure 42 – Yearly profit for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

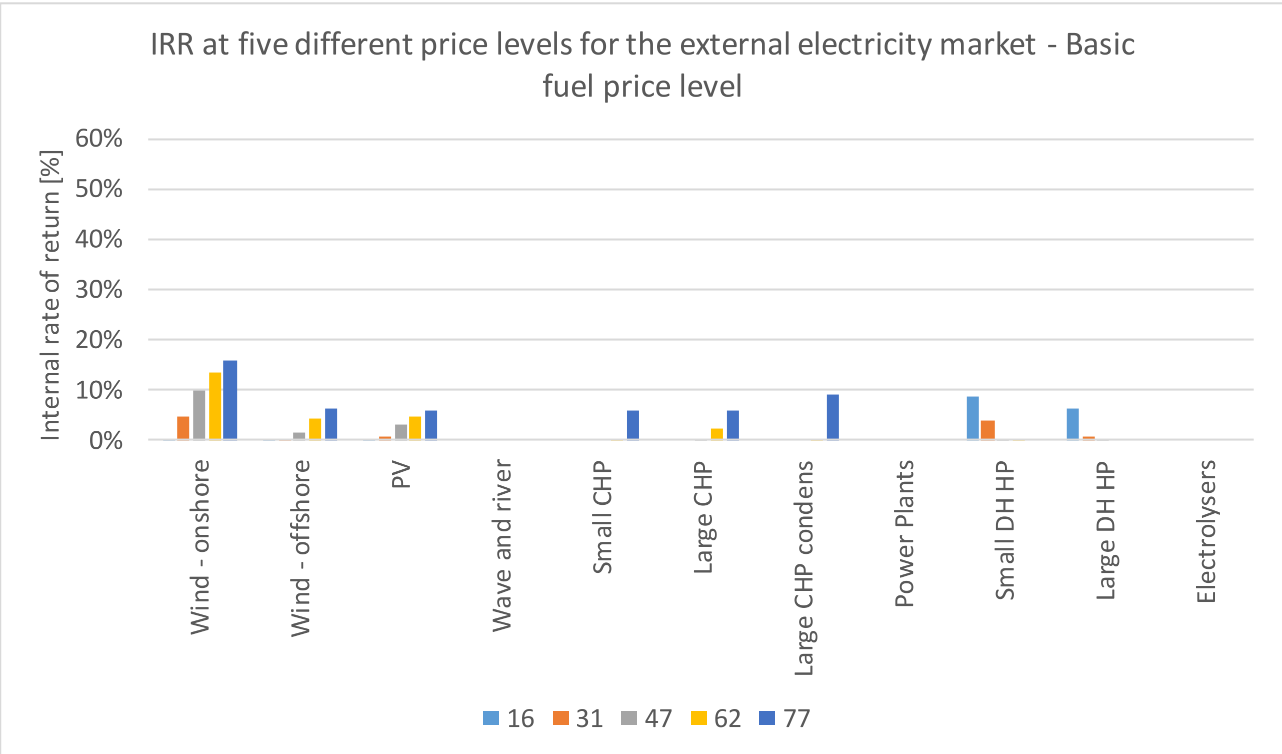

Figure 43 – Internal rate of return for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

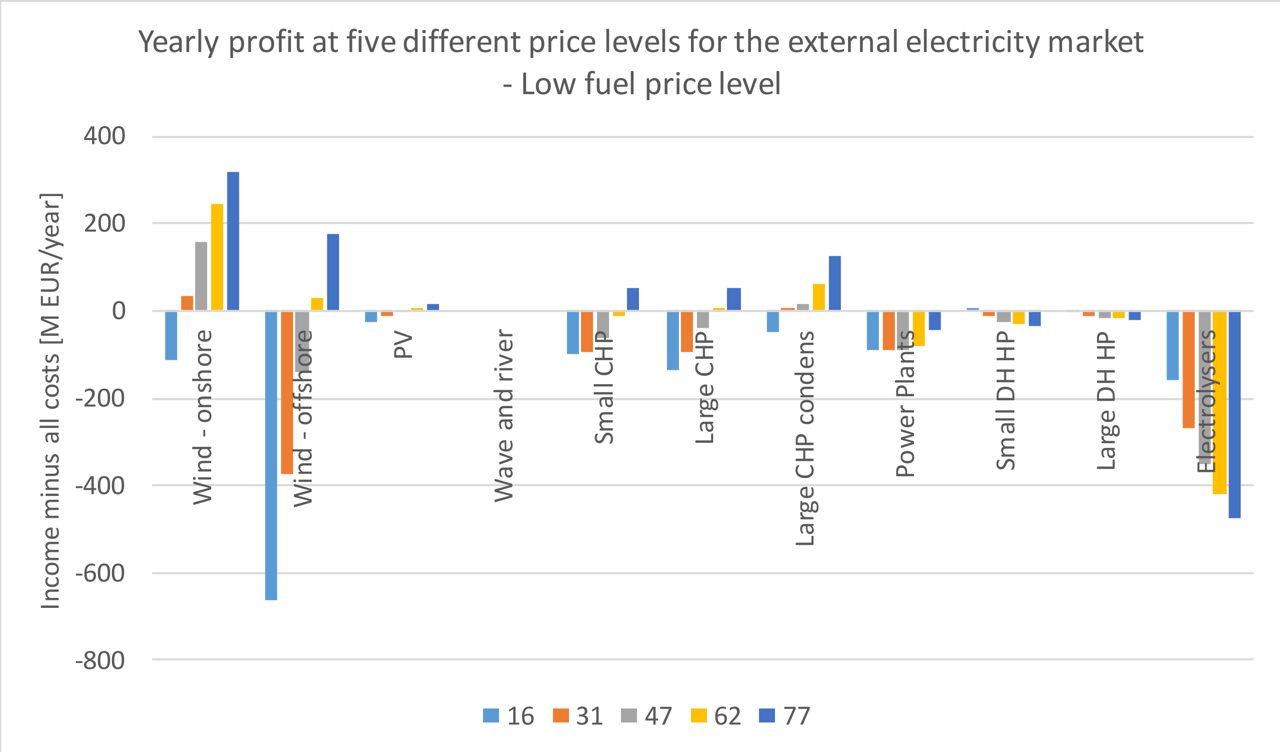

Figure 44 – Yearly profit for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

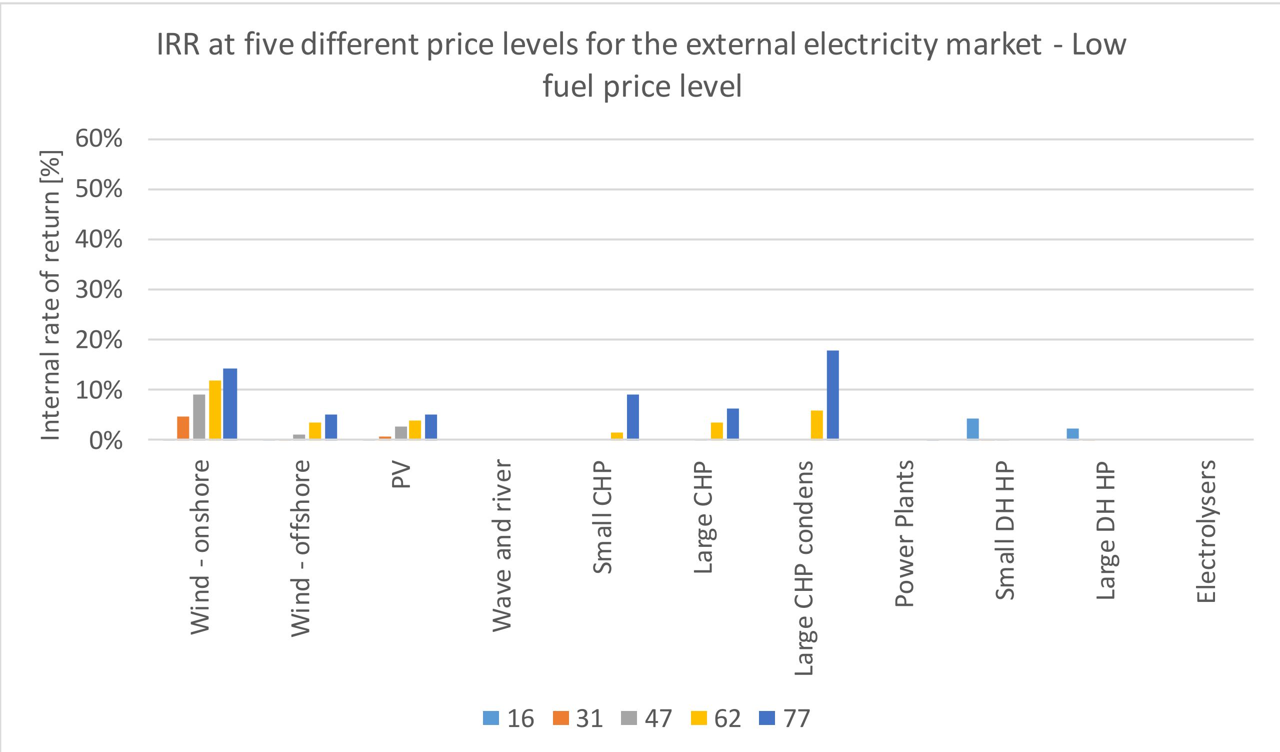

Figure 45 – Internal rate of return for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

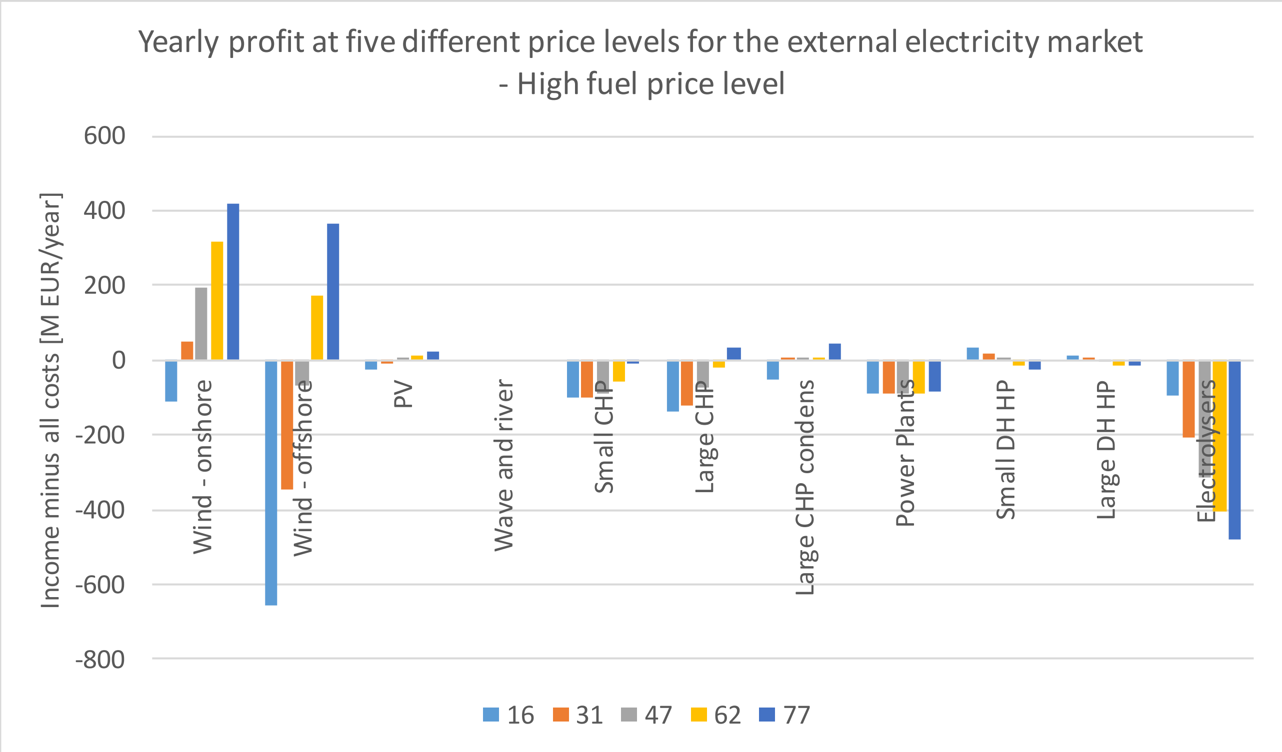

Figure 46 – Yearly profit for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

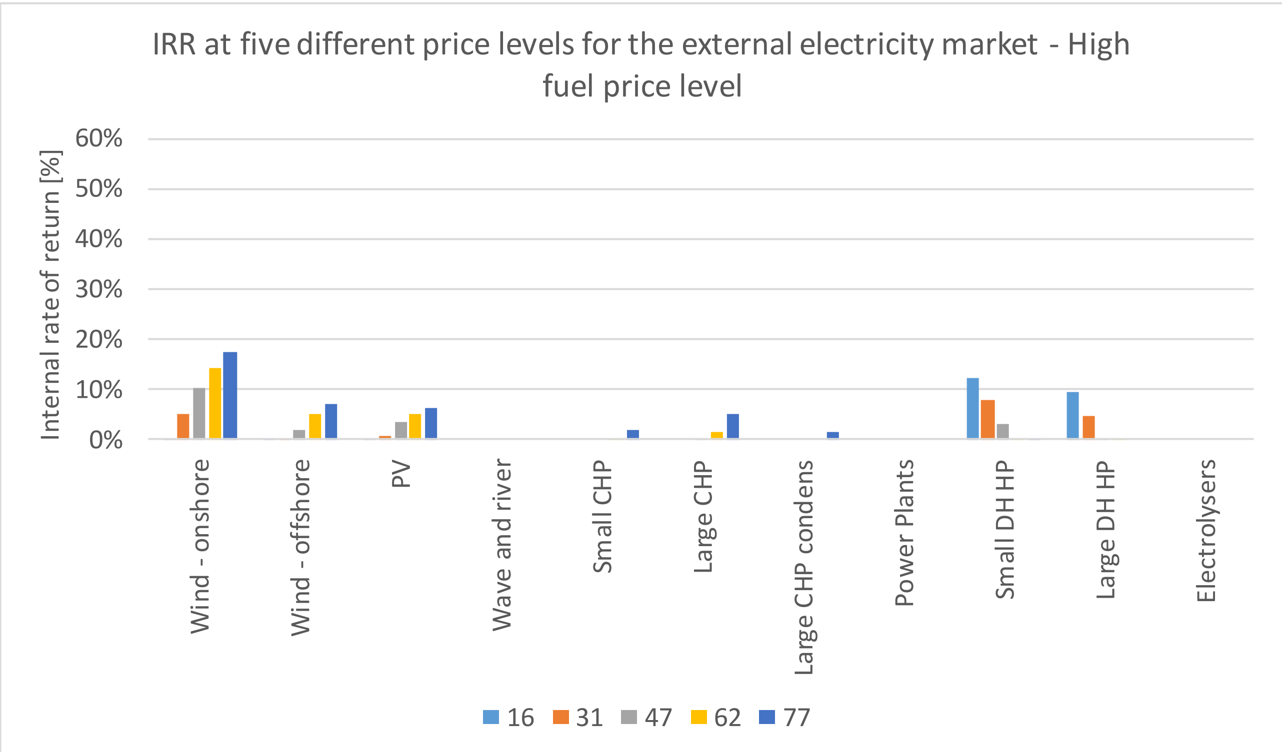

Figure 47 – Internal rate of return for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

Figure 48 shows the lowest value for the produced hydrogen to make the electrolysers (excl. H_2 storage) feasible.

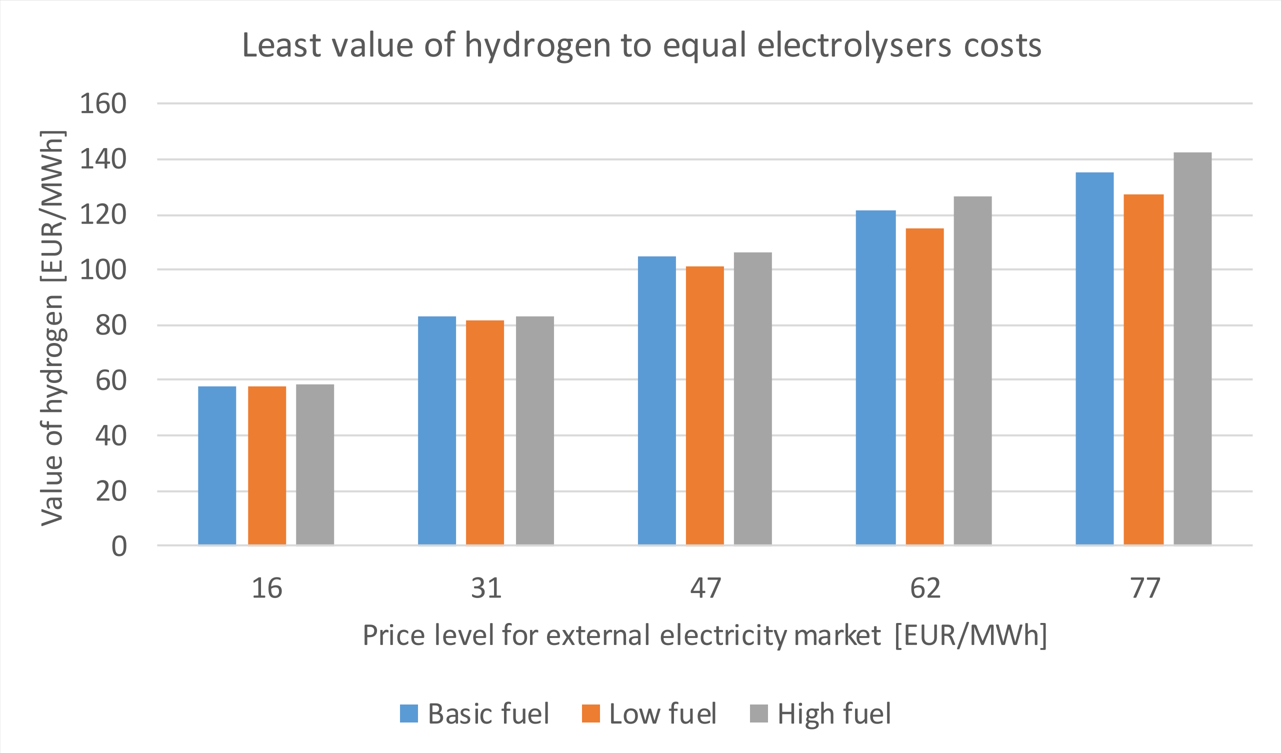

Figure 48 – Least value of hydrogen per MWh produced to equal the costs of operating the electrolysers at each fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

6 DEA wind 2050

6.1 Overview of scenario

Table 14 shows an overview of the main technical and economic characteristic of the electricity producing and main electricity consuming units in the scenario.

General data for units							
	Electric capacity	Electric efficiency	Thermal capacity	Thermal efficiency	Total investment	Annualised investment	Annual fixed O&M
	[MW]	*[%]*	*[MW]*	*[%]*	*[M EUR]*	*[M EUR/a]*	*[M EUR/a]*
Electricity producing units							
Wind - onshore	3500	-	-	-	3150	161	91
Wind - offshore	14000	-	-	-	29680	1514	956
PV	2000	-	-	-	1380	60	14
Wave and river	0	-	-	-	0	0	0
Small CHP	684	49%	600	43%	540	31	21
Large CHP (excl. Condensing)	0	38%	0	52%	0	0	0
- Large CHP condensing operatio	*0*	*44%*	-	-	*0*	*0*	*0*
Power plants	4600	46%	-	-	3634	209	138
Flexible electricity consumption units							
Small DH HP	250	-	800	320%	725	42	14
Large DH HP	78	-	250	320%	227	13	5
Electrolysers	6561	-	-	-	5708	304	228

Table 14 – Overview of relevant units' capacities, efficiencies, investment costs, and annual fixed operation and maintenance (O&M)

For "Electrolysers", only the actual electrolysers are included, meaning that e.g. H2 storage is not included. For "Large CHP (excl. Condensing)", the capacities and efficiencies are only for CHP operation. "Large CHP condensing operation" is the full condensing capacity of the large CHP units, where the investment and fixed O&M costs cover the difference between the electric capacity in CHP operation and the condensing electric capacity.

Figure 49 shows the yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh).

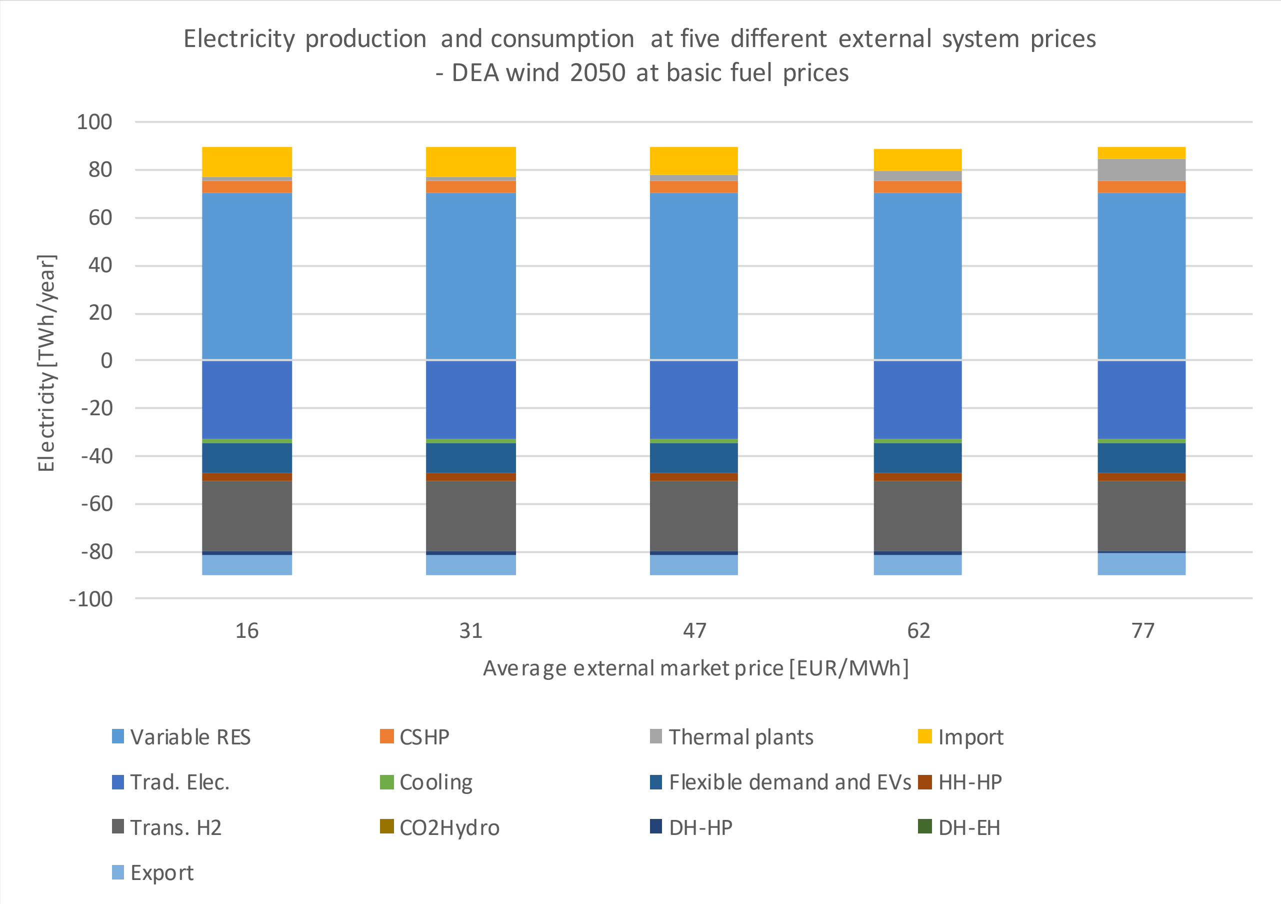

Figure 49 - Yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). RES: Renewable Energy Sources, CSHP: Industrial Combined Heat & Power (incl. waste incineration), HH: Households, HP: Heat Pumps, EV: Electric Vehicle, DH: District Heating, EH: Electric Heating.

6.2 Duration curves for electricity consumption and production

The duration curves shown in this section are only for the average external electricity market price of 77 EUR/MWh.

Figure 50 show the duration curves for different types of residual electricity demands. Residual electricity demand is here understood as the electricity demand minus the variable RES electricity production in any given hour. “Residual hourly fixed” are demands that are fixed on an hourly basis (includes e.g. traditional electricity demands). “Residual hourly and yearly fixed” are both the “Residual hourly fixed” as well as any electricity demands that are fixed on a yearly basis (includes e.g. flexible charged electric vehicles). “All residual” are all residual electricity demands (includes e.g. heat pumps in district heating). Figure 51 show the electricity production duration curves for CSHP, variable RES, and thermal plants.

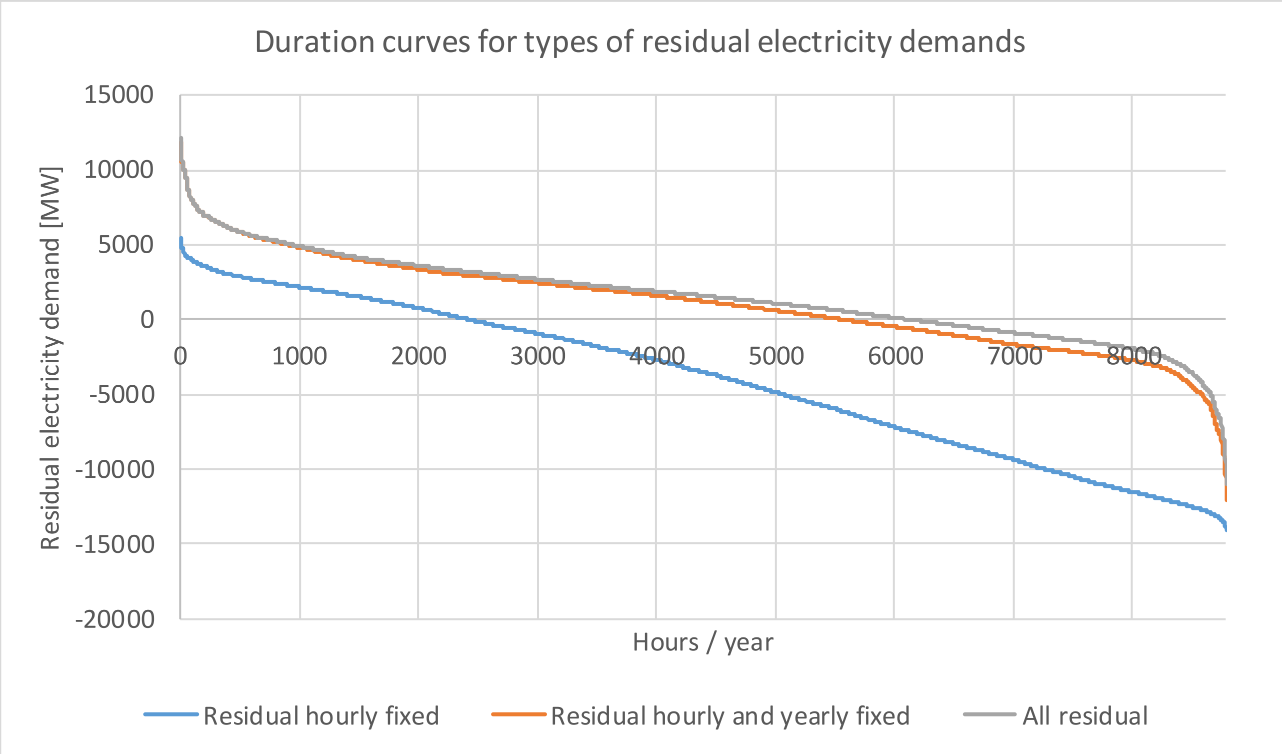

Figure 50 – Duration curves for different types of residual electricity demands at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

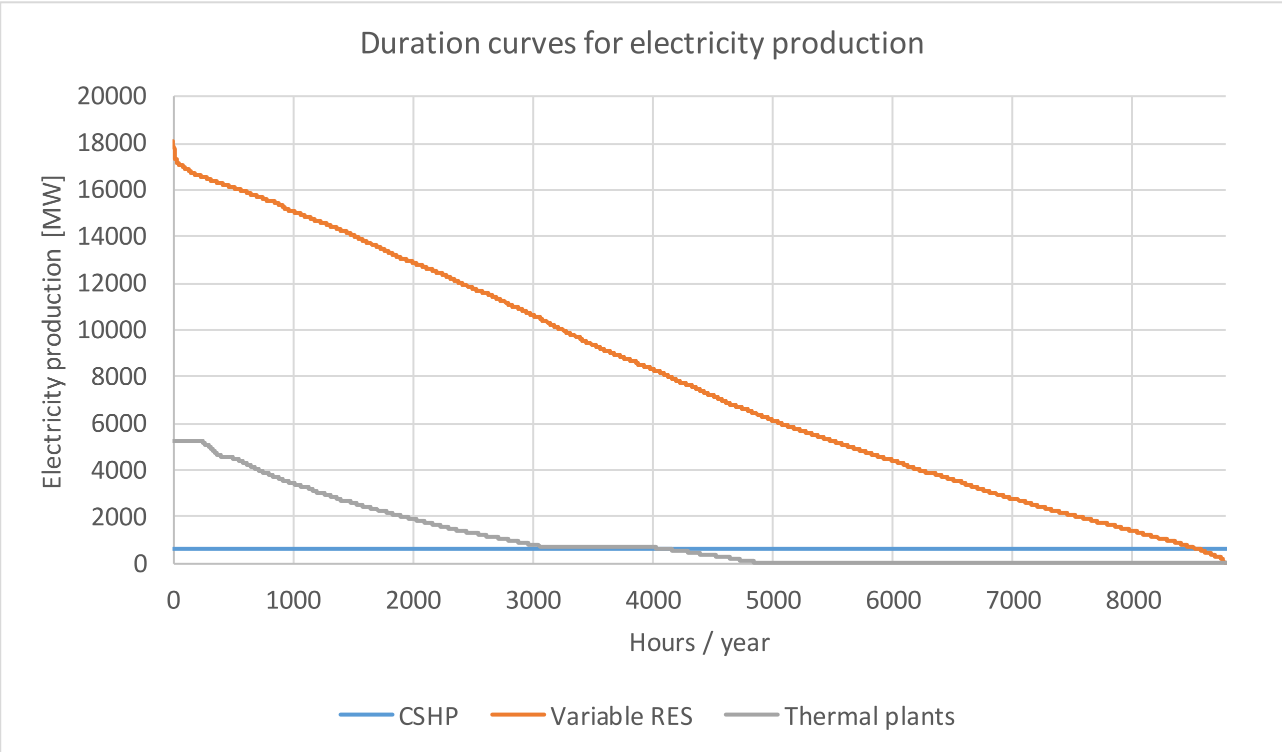

Figure 51 – Duration curves for electricity production by different unit types at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

6.3 Electricity prices

Figure 52, Figure 53, and Figure 54 show for each of the three fuel price levels the resulting hourly electricity market system price using five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). Table 15, Table 16, and Table 17 show the corresponding resulting average, minimum, and maximum electricity price in the simulation.

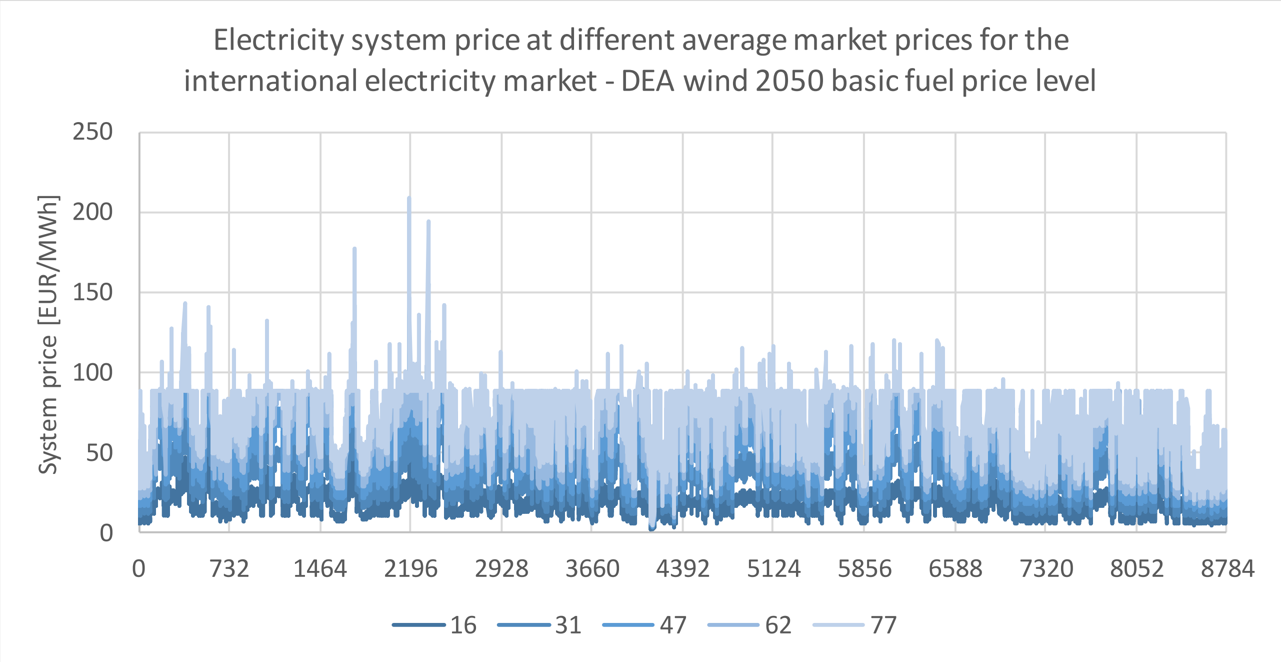

Figure 52 – Hourly system price on Nord Pool Spot at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	18	34	50	63	72
Resulting min	2	3	3	4	4
Resulting max	67	88	126	155	209

Table 15 - Resulting yearly average, minimum and maximum electricity prices at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

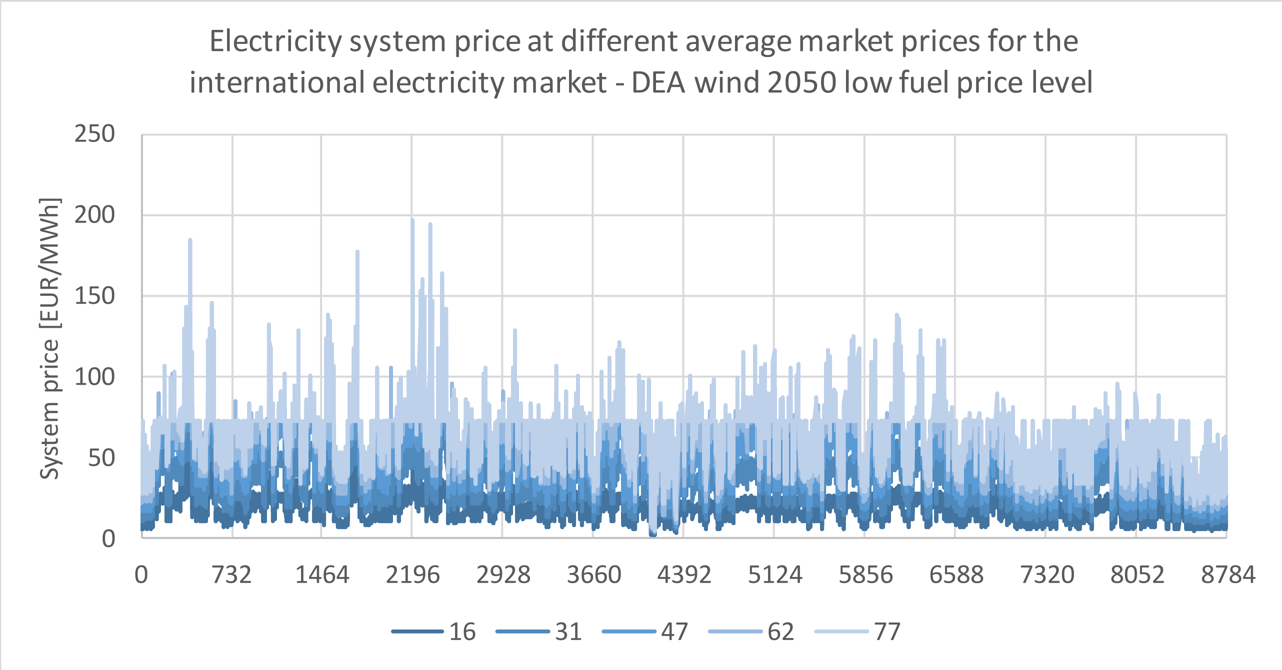

Figure 53 – Hourly system price on Nord Pool Spot at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	18	34	49	59	65
Resulting min	2	3	3	4	4
Resulting max	66	84	117	158	197

Table 16 - Resulting yearly average, minimum and maximum electricity prices at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

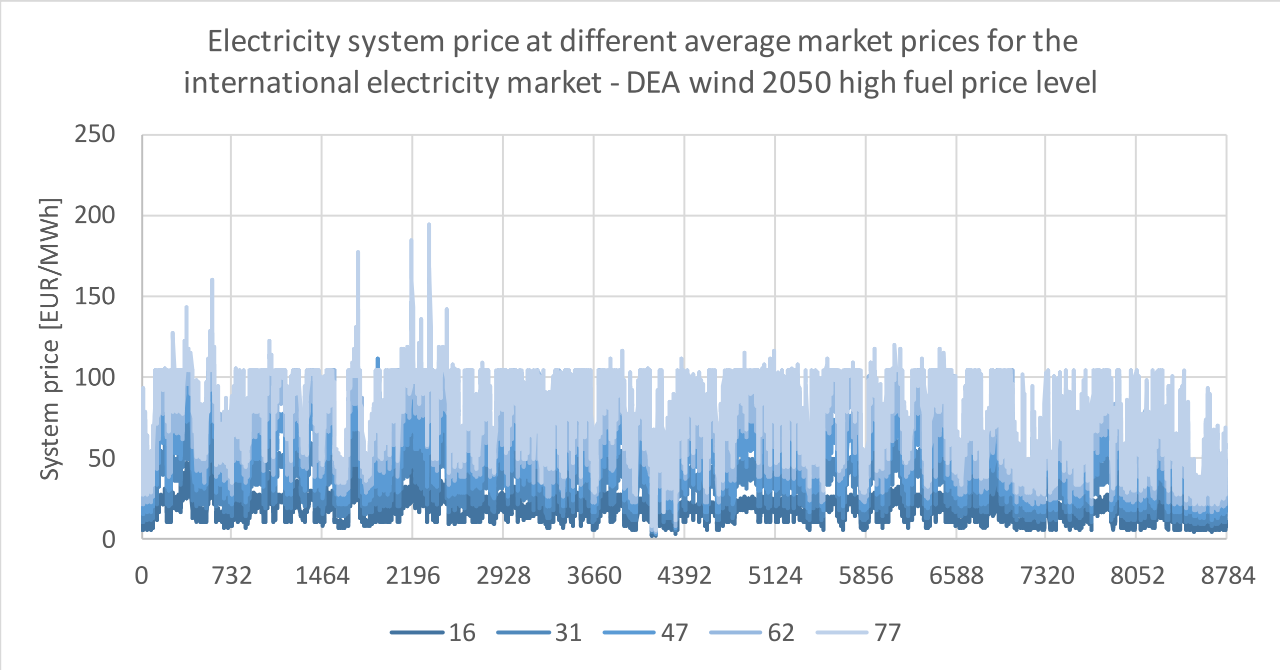

Figure 54 – Hourly system price on Nord Pool Spot at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	18	34	50	65	77
Resulting min	2	3	3	4	5
Resulting max	67	104	126	167	194

Table 17 - Resulting yearly average, minimum and maximum electricity prices at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

6.4 Marginal activated unit

The purpose of this section is to identify the marginal activated unit in the simulated energy system. This is done by first separating the array for the electricity market price into arrays with the marginal price of each unit being the lower limit of an array and the next marginal most expensive unit being the upper limit. E.g. “Incr. B2 decr. EB2” has a marginal price of 38 and the next least expensive unit is “Incr. CHP2 decr. B2” with a marginal price of 67, resulting in the “Incr. B2 decr. EB2” array being prices between 38 and 67. After the arrays have been established, it is for each hour checked whether the activated technology was in fact in use or not. If not, then if there is variable RES in operation this becomes the marginal activated unit. If there is no variable RES in operation, then it that hour is added to the “Rest” category (i.e. the external market is the marginal “unit”). This approach only account for the units activated within the simulated energy system and does not account for what units are activated outside of the simulated energy system in case of import and export of electricity.

This is done for each of the three fuel price levels, as well as the five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). See Figure 55, Figure 56, and Figure 57.

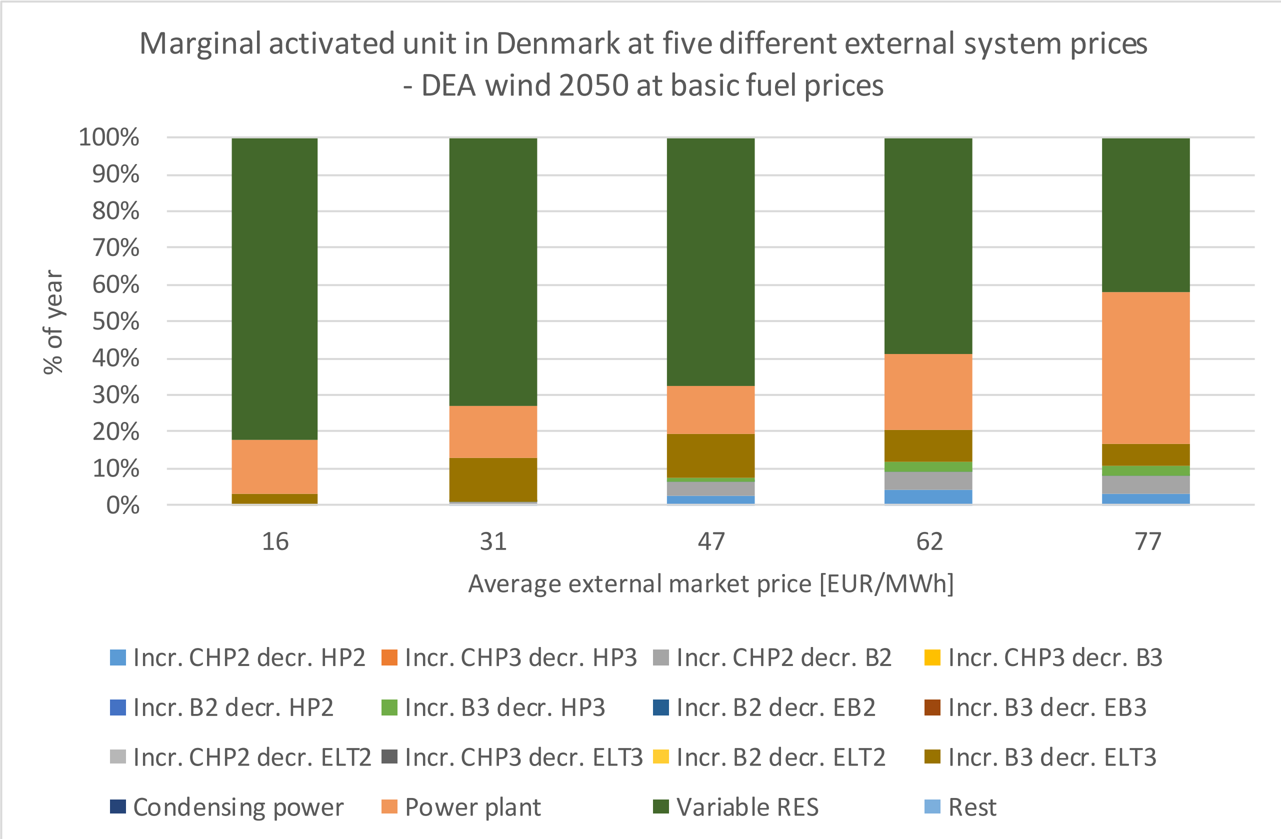

Figure 55 – Marginal activated unit in Denmark at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

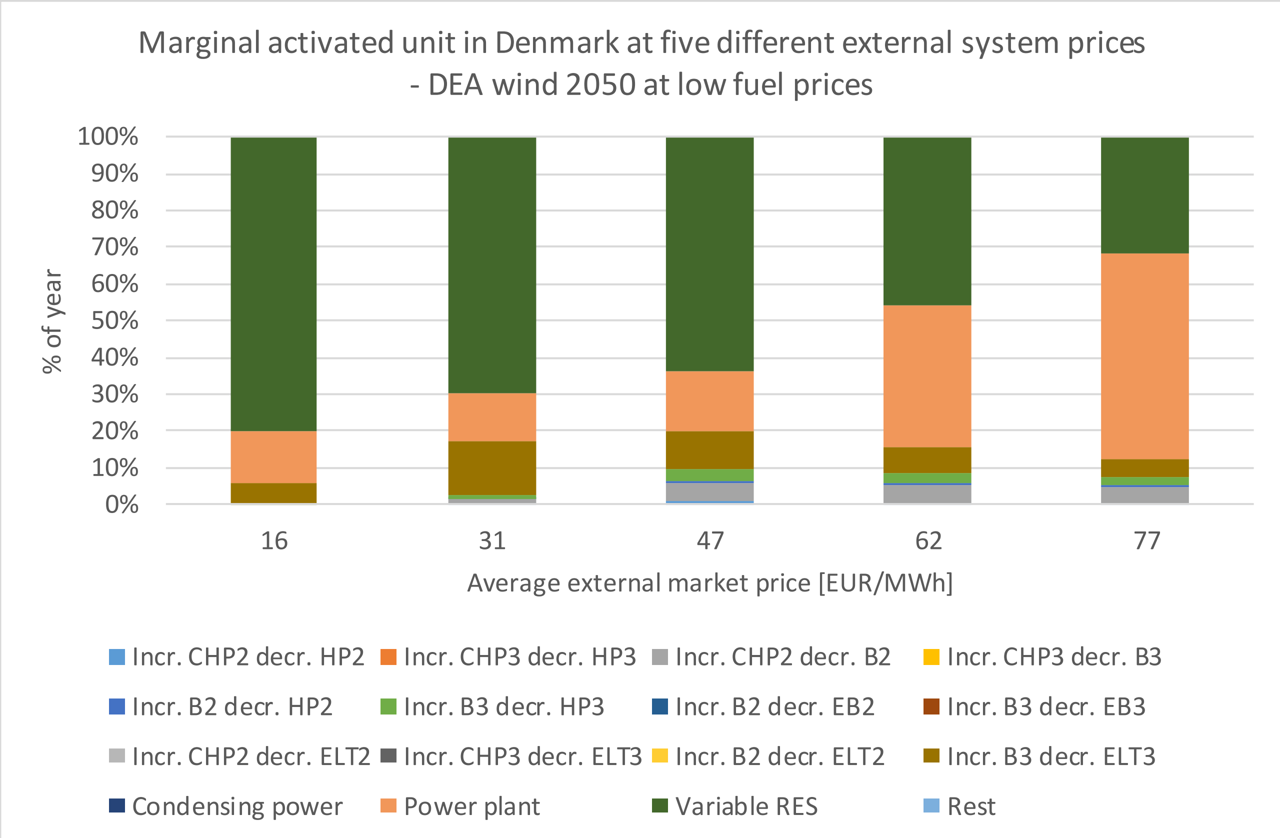

Figure 56 – Marginal activated unit in Denmark at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

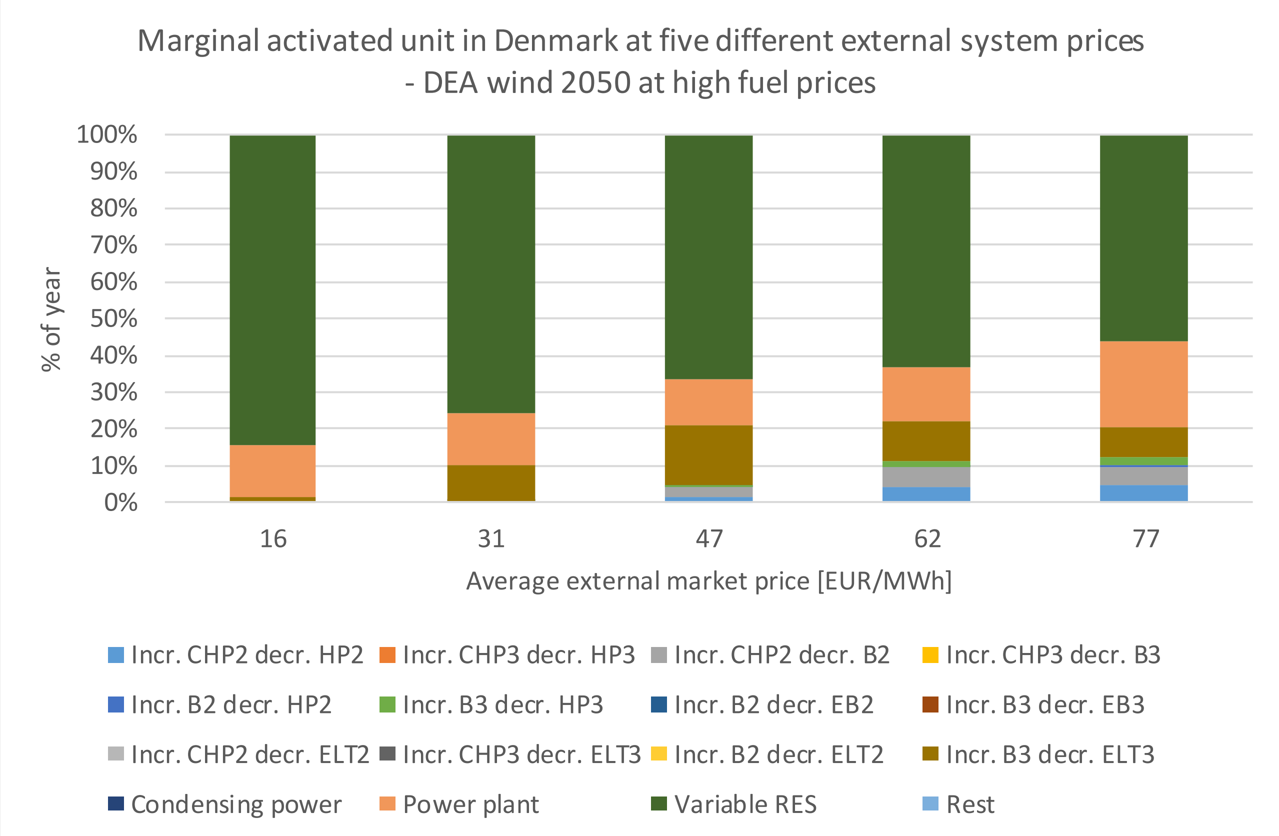

Figure 57 – Marginal activated unit in Denmark at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

6.5 Profit analysis

The aim of this analysis is to identify which types of units are expected to be able to cover their own costs in the current Nord Pool Spot regime. Only costs directly related to the specific units are included (investment, fixed O&M, variable O&M, fuel costs, and CO_2-costs). As such, potential related costs, e.g. grid costs and storage costs, are not included. For the income, only sale of electricity on Nord Pool Spot (as modelled in EnergyPLAN), sale of produced district heating and sale of hydrogen are included. For sale of district heating, it is assumed that the value of the produced heat is equal to the short-marginal cost of an average fuel boiler in the corresponding district heating group.

Figure 58, Figure 60, and Figure 62 show the yearly profit of each unit type where a discount rate of 3% has been used. Figure 59, Figure 61, and Figure 63 show the corresponding internal rate of return (IRR). The only incomes being sale of electricity on Nord Pool Spot, sale of heat for district heating, and sale of hydrogen. In these figures, the sale of hydrogen is simply assumed to equal the natural gas price. Figure 64 shows what the lowest value for the produced hydrogen should be to make the electrolysers feasible. Each figure represents a different fuel price level.

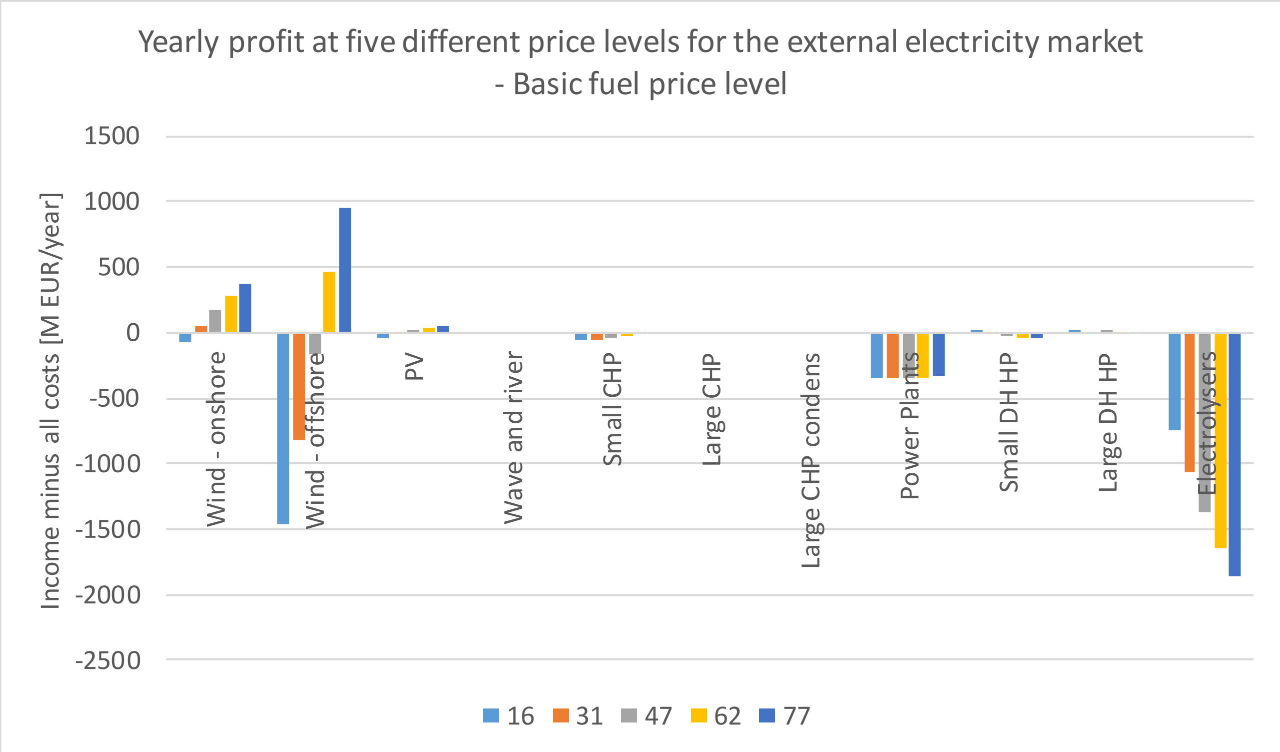

Figure 58 – Yearly profit for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

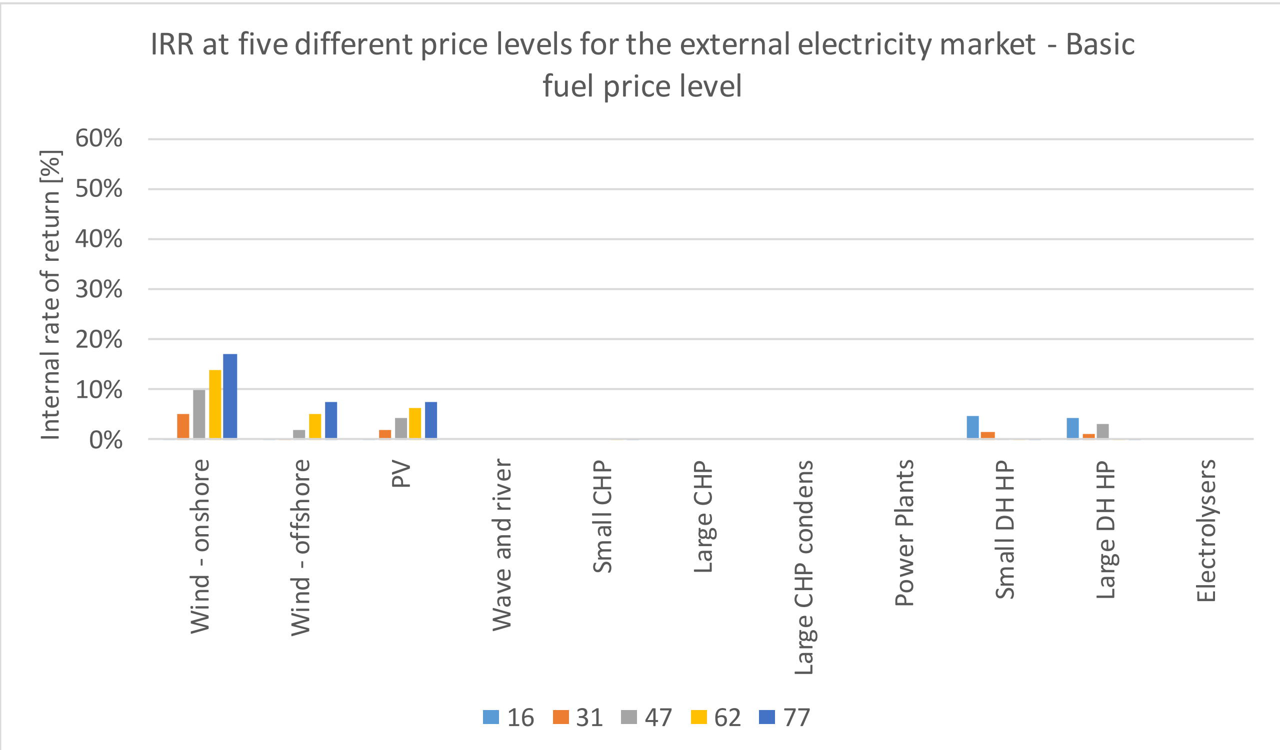

Figure 59 – Internal rate of return for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

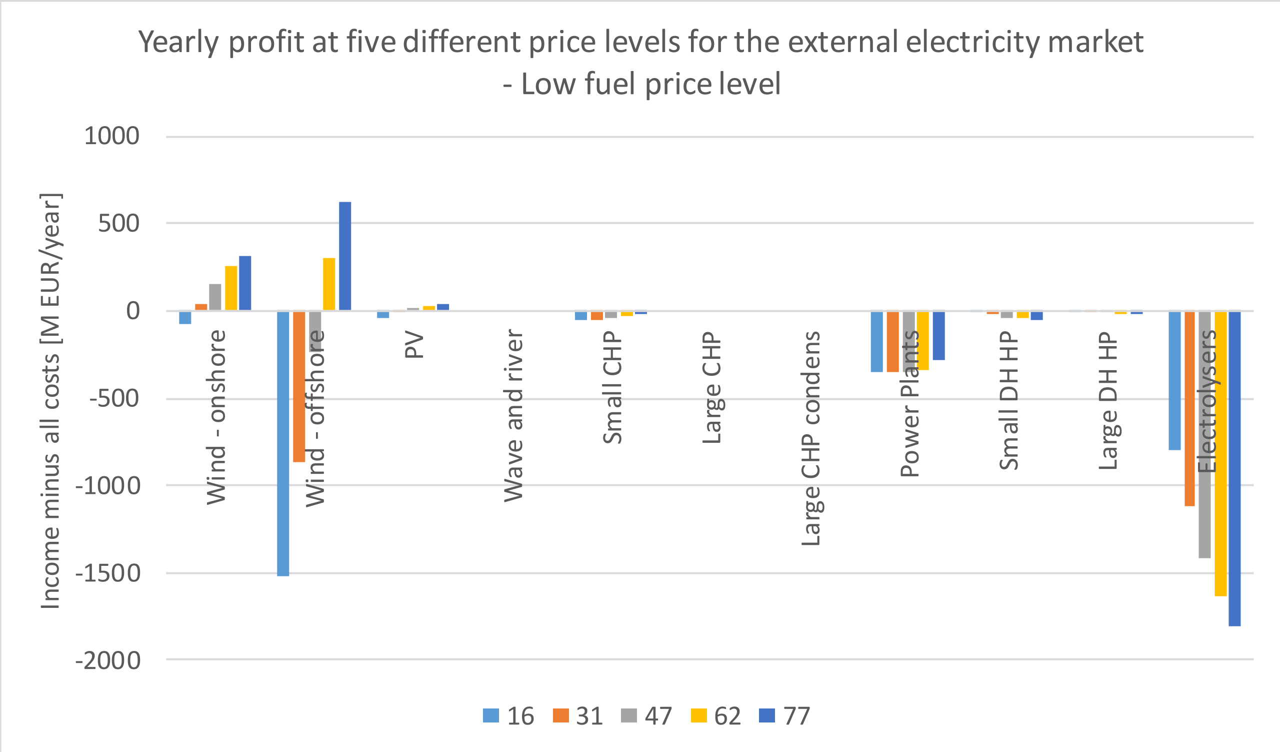

Figure 60 – Yearly profit for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

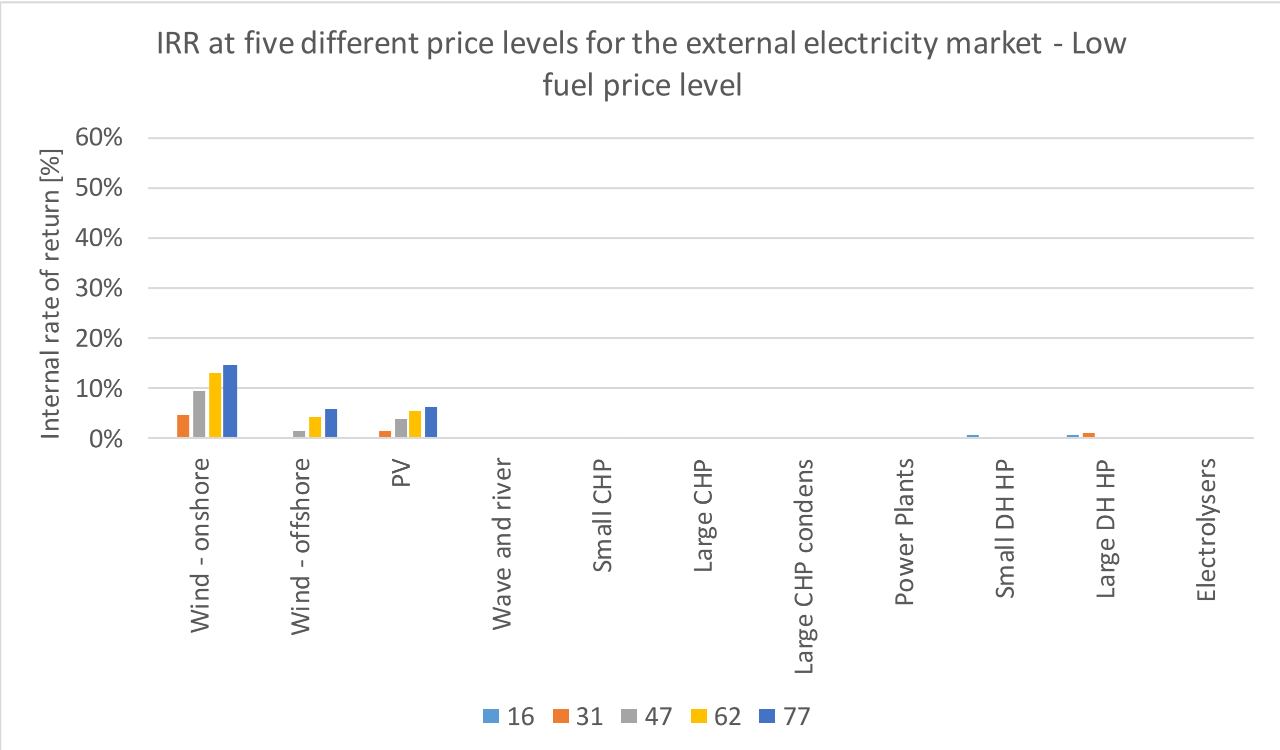

Figure 61 – Internal rate of return for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

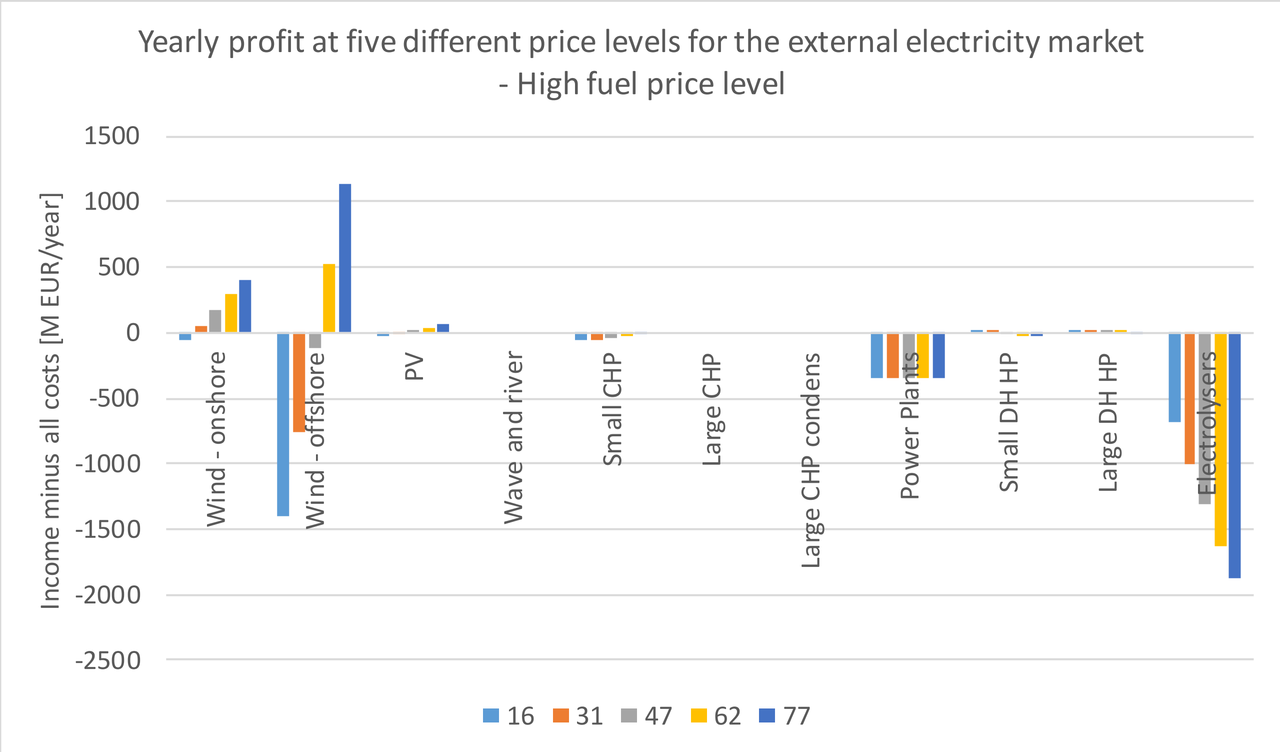

Figure 62 – Yearly profit for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

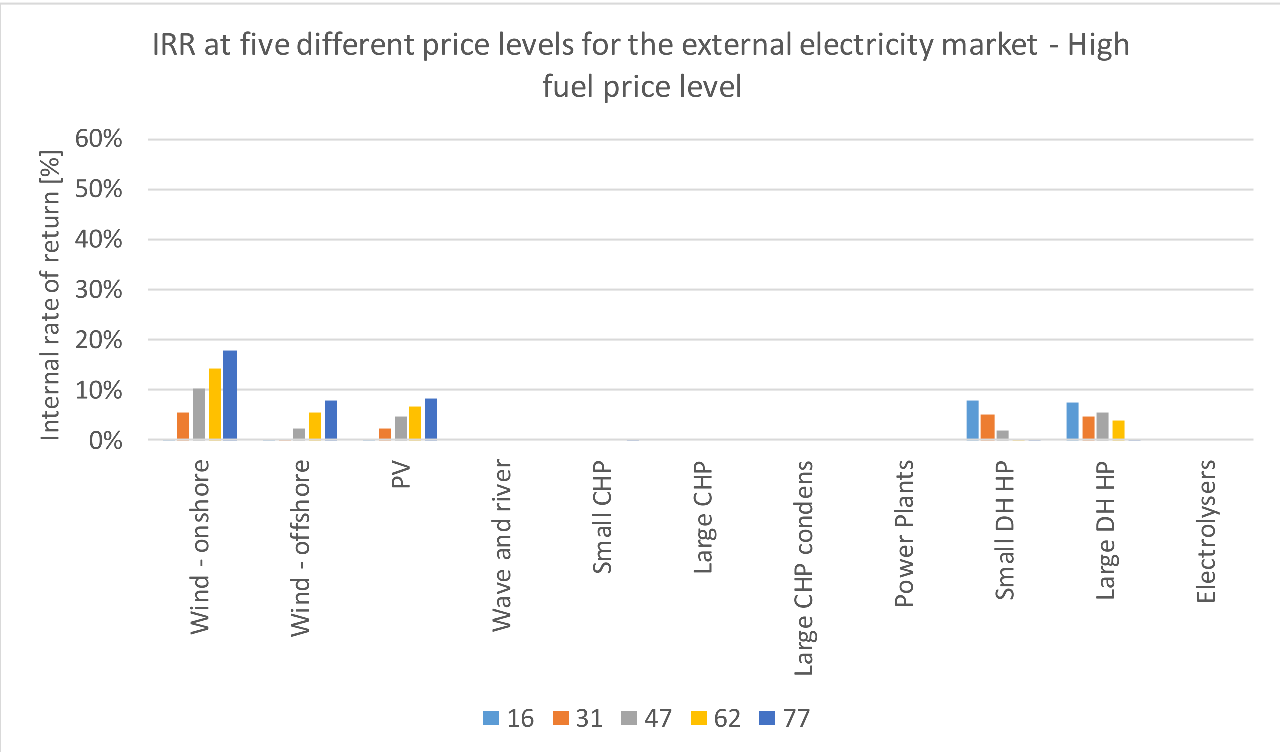

Figure 63 – Internal rate of return for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

Figure 64 shows the lowest value for the produced hydrogen to make the electrolysers (excl. H_2 storage) feasible.

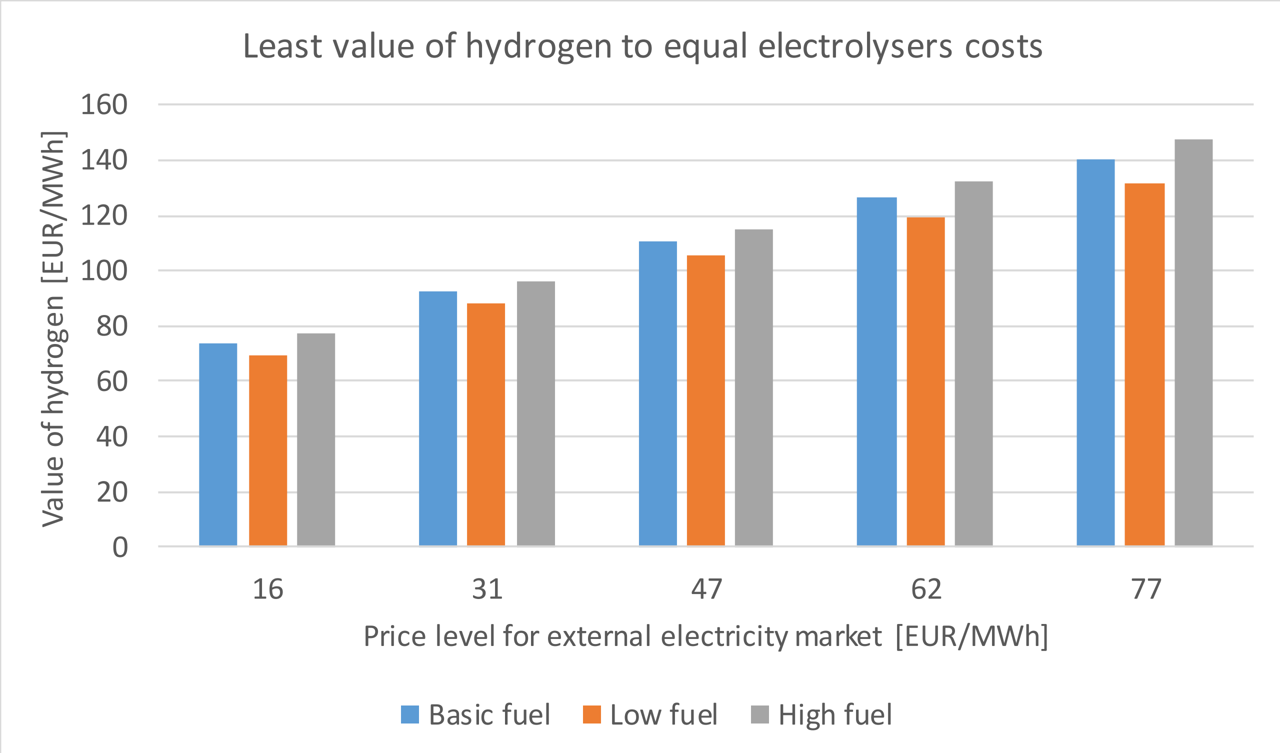

Figure 64 – Least value of hydrogen per MWh produced to equal the costs of operating the electrolysers at each fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

7 IDA 2035

7.1 Overview of scenario

Table 18 shows an overview of the main technical and economic characteristic of the electricity producing and main electricity consuming units in the scenario.

General data for units							
	Electric capacity	Electric efficiency	Thermal capacity	Thermal efficiency	Total investment	Annualised investment	Annual fixed O&M
	[MW]	*[%]*	*[MW]*	*[%]*	*[M EUR]*	*[M EUR/a]*	*[M EUR/a]*
Electricity producing units							
Wind - onshore	3875	-	-	-	3875	223	101
Wind - offshore	5887	-	-	-	14305	822	421
PV	3127	-	-	-	2564	111	26
Wave and river	176	-	-	-	590	34	6
Small CHP	1026	52%	770	39%	1231	71	46
Large CHP (excl. Condensing)	1926	49%	1657	42%	2687	132	89
- Large CHP condensing operatio	*4500*	*57%*	-	-	*3590*	*176*	*118*
Power plants	0	0%	-	-	0	0	0
Flexible electricity consumption units							
Small DH HP	300	-	900	300%	1029	59	21
Large DH HP	400	-	1200	300%	1300	75	26
Electrolysers	2454	-	-	-	859	72	26

Table 18 – Overview of relevant units' capacities, efficiencies, investment costs, and annual fixed operation and maintenance (O&M)

For "Electrolysers", only the actual electrolysers are included, meaning e.g. H2 storage is not included. For "Large CHP (excl. Condensing)", the capacities and efficiencies are only for CHP operation. "Large CHP condensing operation" is the full condensing capacity of the large CHP units, where the investment and fixed O&M costs cover the difference between the electric capacity in CHP operation and the condensing electric capacity.

Figure 65 shows the yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh).

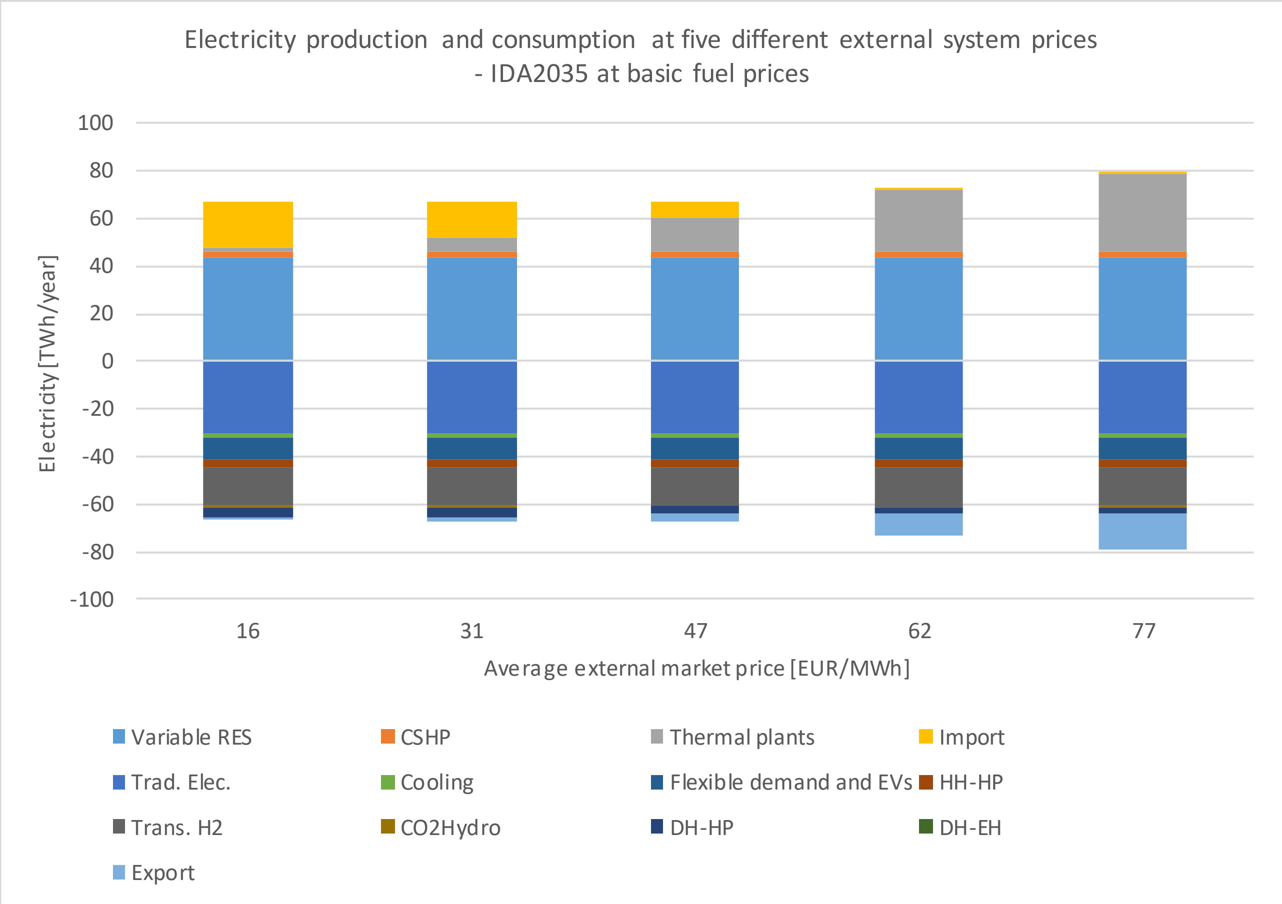

Figure 65 - Yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). RES: Renewable Energy Sources, CSHP: Industrial Combined Heat & Power (incl. waste incineration), HH: Households, HP: Heat Pumps, EV: Electric Vehicle, DH: District Heating, EH: Electric Heating.

7.2 Duration curves for electricity consumption and production

The duration curves shown in this section are only for the average external electricity market price of 77 EUR/MWh.

Figure 66 show the duration curves for different types of residual electricity demands. Residual electricity demand is here understood as the electricity demand minus the variable RES electricity production in any given hour. “Residual hourly fixed” are demands that are fixed on an hourly basis (includes e.g. traditional electricity demands). “Residual hourly and yearly fixed” are both the “Residual hourly fixed” as well as any electricity demands that are fixed on a yearly basis (includes e.g. flexible charged electric vehicles). “All residual” are all residual electricity demands (includes e.g. heat pumps in district heating). Figure 67 show the electricity production duration curves for CSHP, variable RES, and thermal plants.

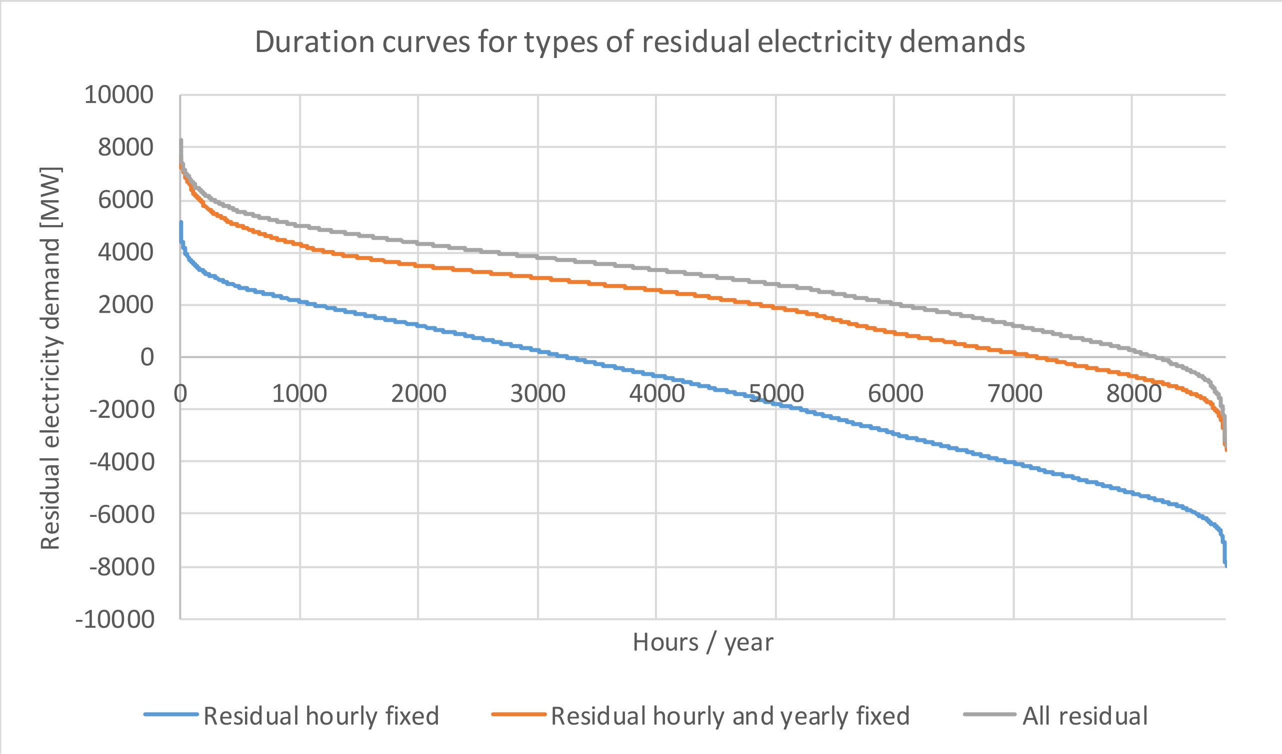

Figure 66 – Duration curves for different types of residual electricity demands at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

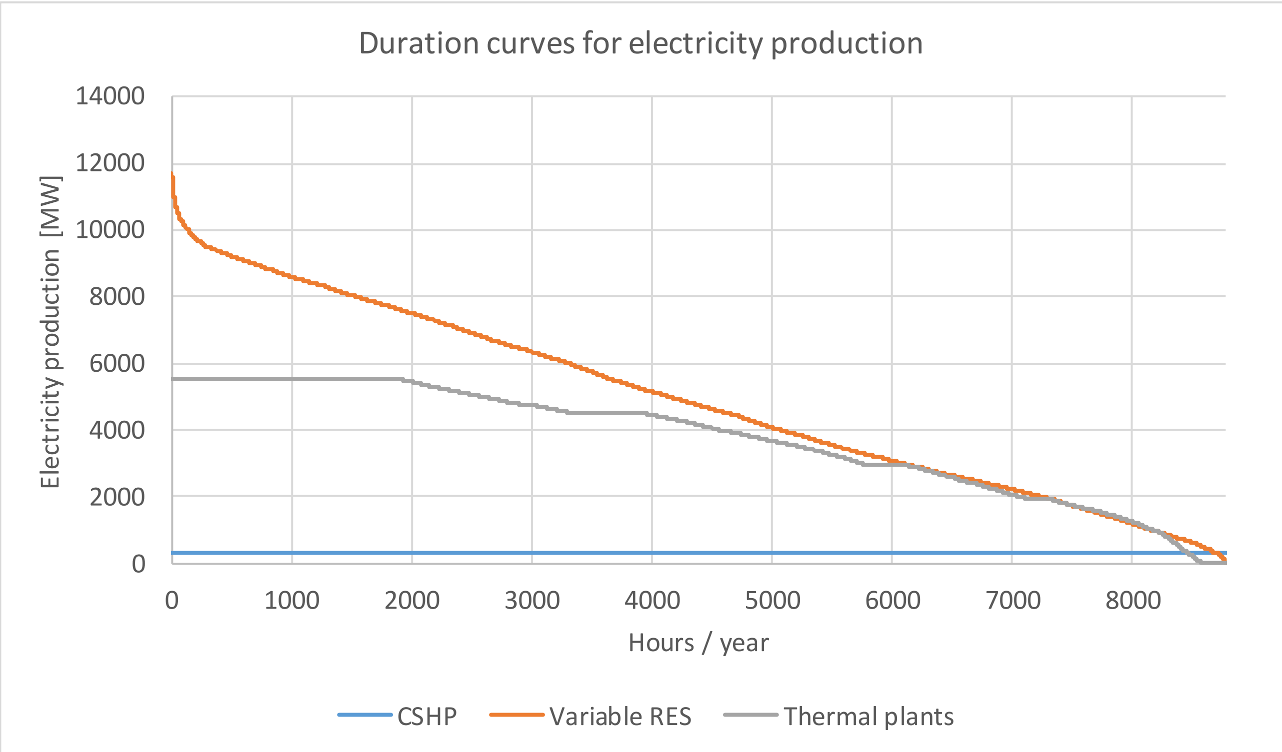

Figure 67 – Duration curves for electricity production by different unit types at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

7.3 Electricity prices

Figure 68, Figure 69, and Figure 70 show for each of the three fuel price levels the resulting hourly electricity market system price using five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). Table 19, Table 20, and Table 21 show the corresponding resulting average, minimum, and maximum electricity price in the simulation.

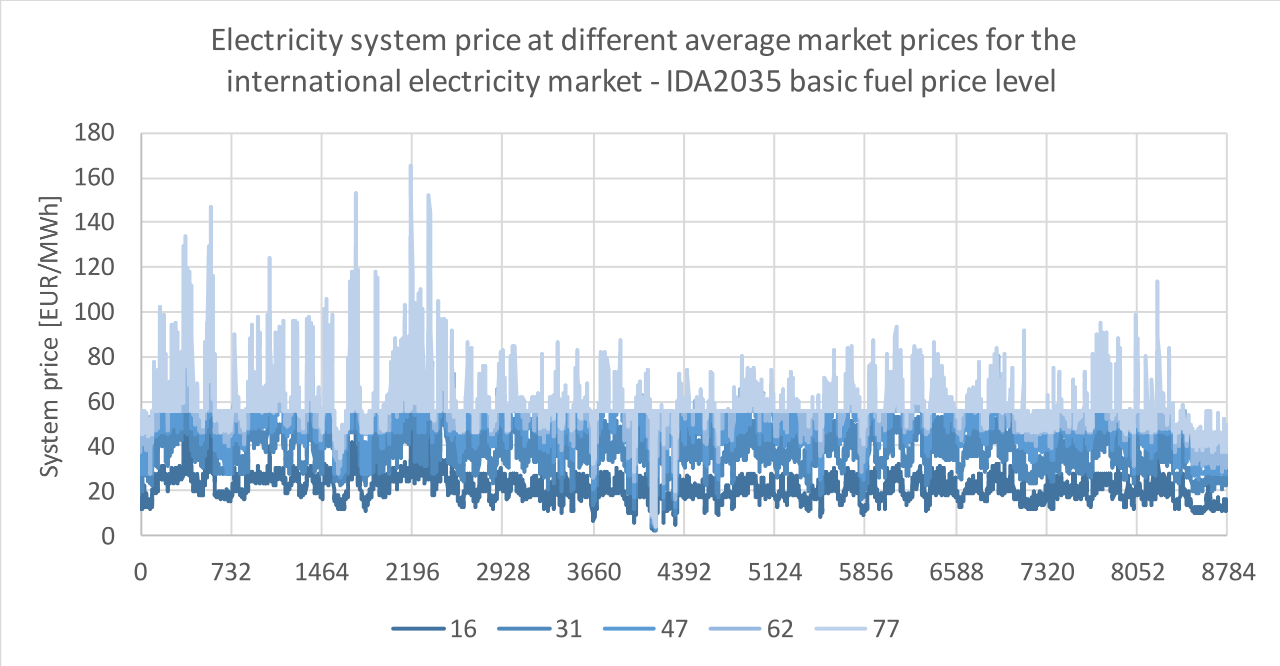

Figure 68 – Hourly system price on Nord Pool Spot at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	21	38	49	54	59
Resulting min	2	2	3	4	4
Resulting max	56	69	98	134	165

Table 19 - Resulting yearly average, minimum and maximum electricity prices at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

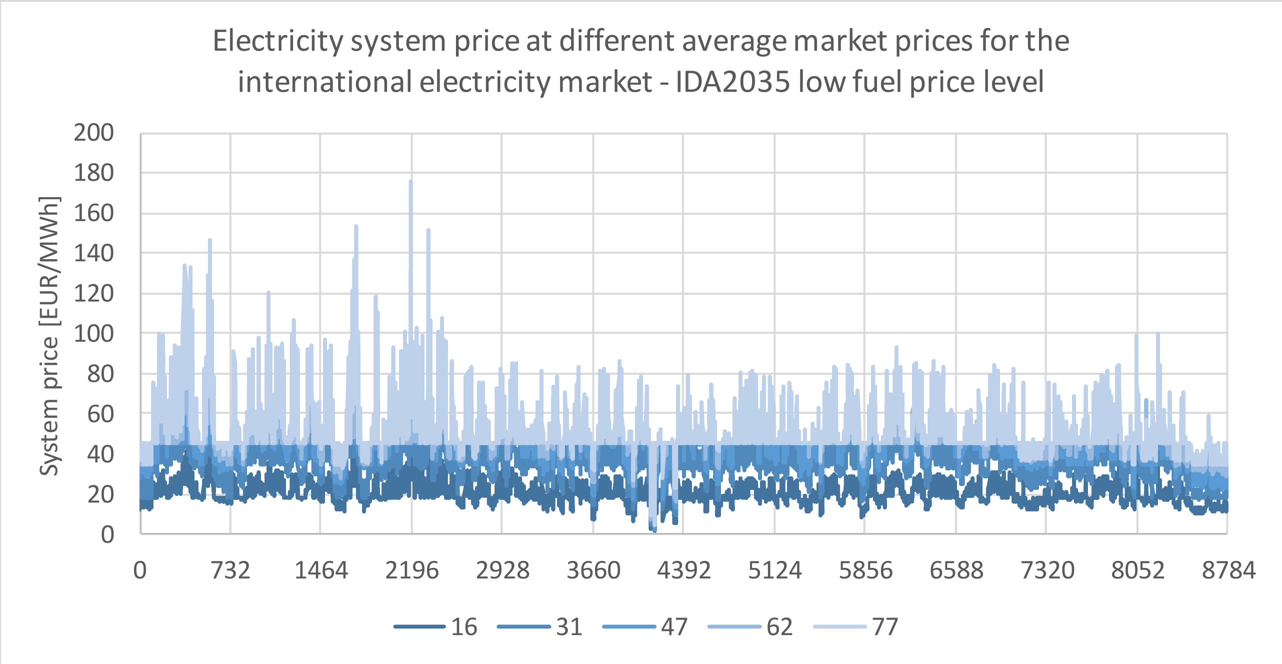

Figure 69 – Hourly system price on Nord Pool Spot at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	20	35	42	47	52
Resulting min	2	2	3	4	4
Resulting max	45	70	100	132	176

Table 20 - Resulting yearly average, minimum and maximum electricity prices at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

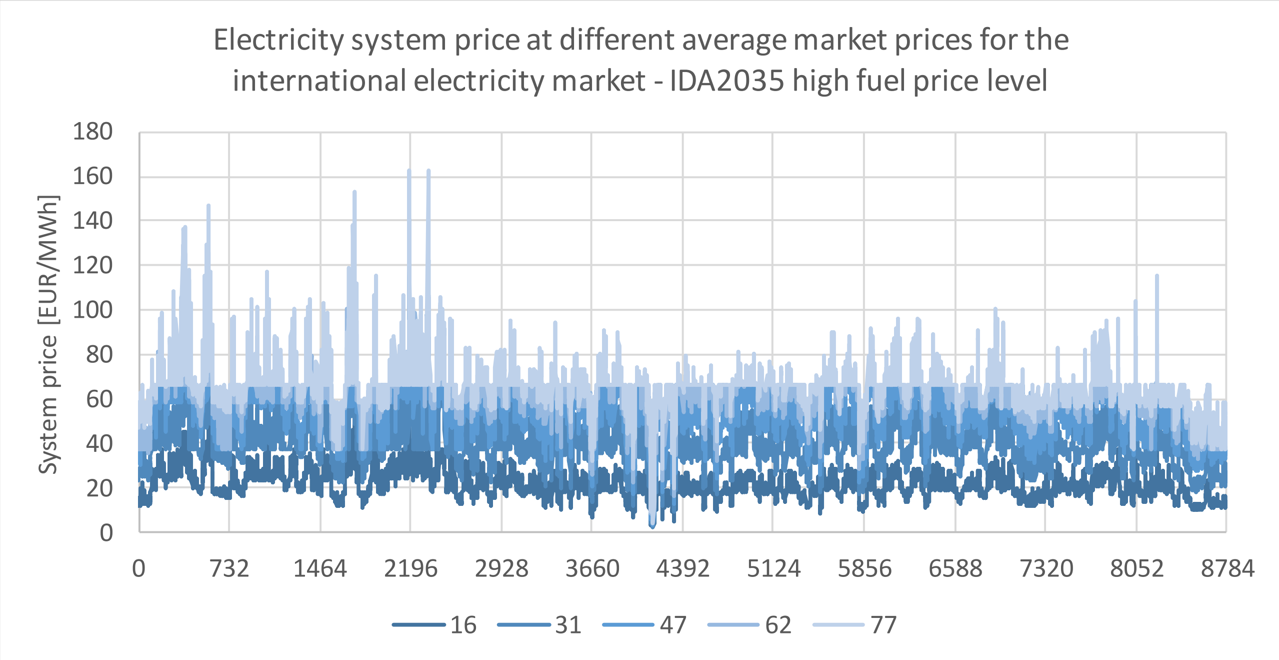

Figure 70 – Hourly system price on Nord Pool Spot at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	21	39	53	60	65
Resulting min	2	2	3	4	4
Resulting max	58	72	104	141	163

Table 21 - Resulting yearly average, minimum and maximum electricity prices at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

7.4 Marginal activated unit

The purpose of this section is to identify the marginal activated unit in the simulated energy system. This is done by first separating the array for the electricity market price into arrays with the marginal price of each unit being the lower limit of an array and the next marginal most expensive unit being the upper limit. E.g. “Incr. B2 decr. EB2” has a marginal price of 38 and the next least expensive unit is “Incr. CHP2 decr. B2” with a marginal price of 67, resulting in the “Incr. B2 decr. EB2” array being prices between 38 and 67. After the arrays have been established, it is for each hour checked whether the activated technology was in fact in use or not. If not, then if there is variable RES in operation this becomes the marginal activated unit. If there is no variable RES in operation, then it that hour is added to the “Rest” category (i.e. the external market is the marginal “unit”). This approach only account for the units activated within the simulated energy system and does not account for what units are activated outside of the simulated energy system in case of import and export of electricity.

This is done for each of the three fuel price levels, as well as the five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). See Figure 71, Figure 72, and Figure 73.

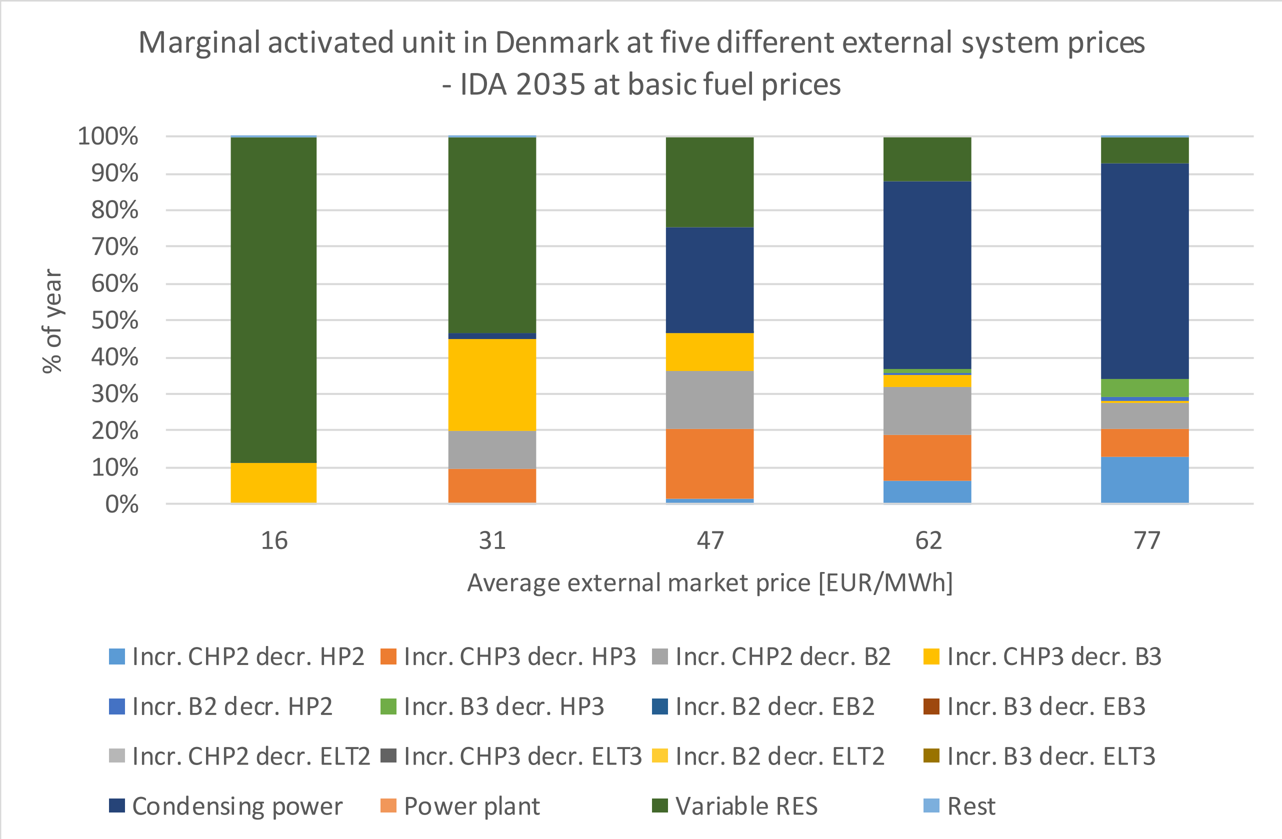

Figure 71 – Marginal activated unit in Denmark at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

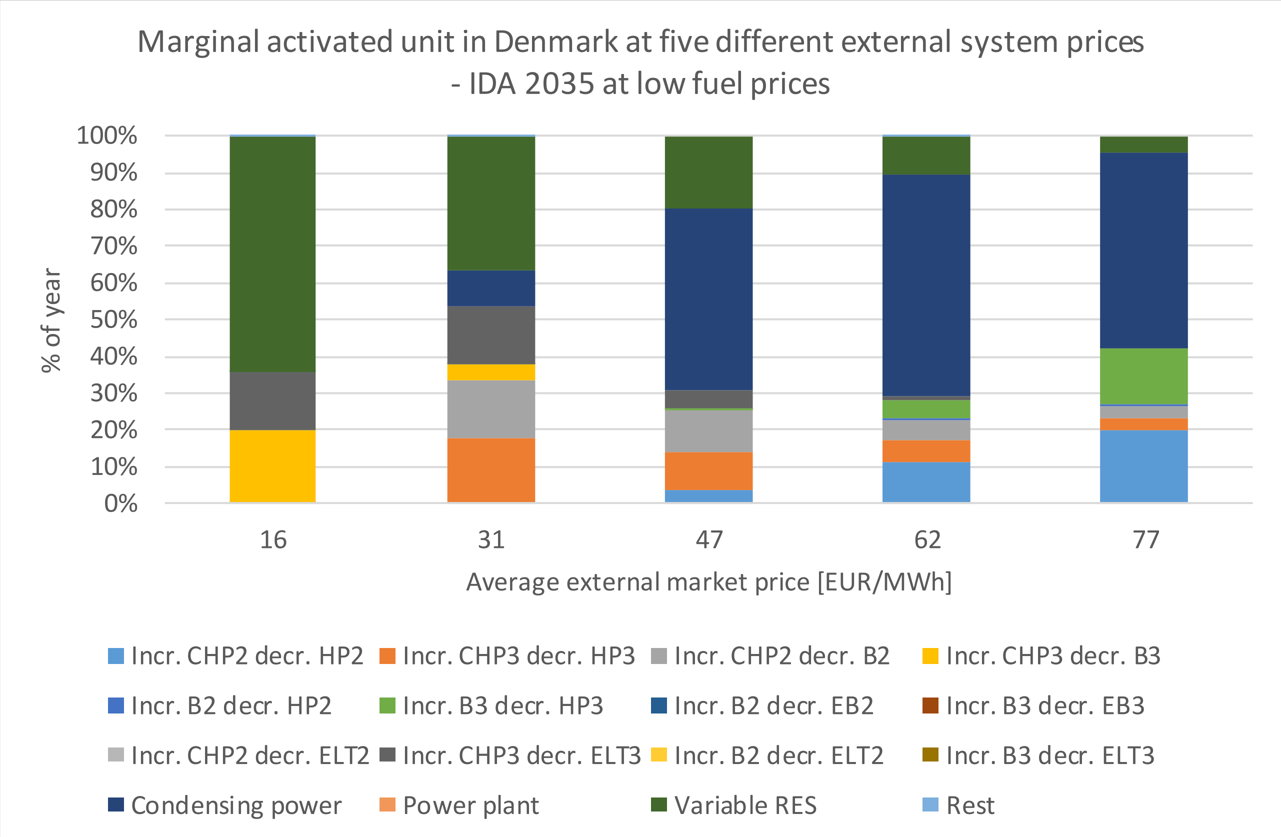

Figure 72 – Marginal activated unit in Denmark at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

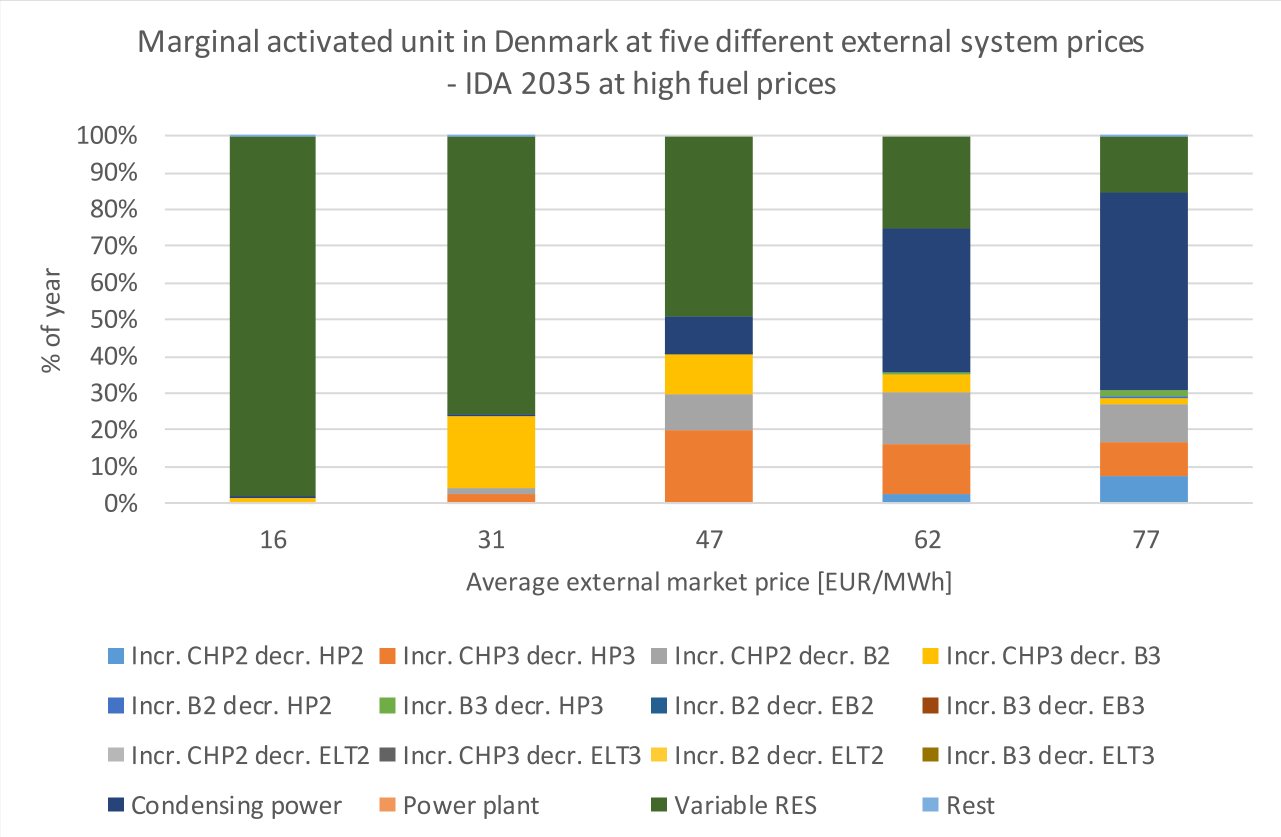

Figure 73 – Marginal activated unit in Denmark at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

7.5 Profit analysis

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Figure 74, Figure 76, and Figure 78 show the yearly profit of each unit type where a discount rate of 3% has been used. Figure 75, Figure 77, and Figure 79 show the corresponding internal rate of return (IRR). The only incomes being sale of electricity on Nord Pool Spot, sale of heat for district heating, and sale of hydrogen. In these figures, the sale of hydrogen is simply assumed to equal the natural gas price. Figure 80 shows what the lowest value for the produced hydrogen should be to make the electrolysers feasible. Each figure represents a different fuel price level.

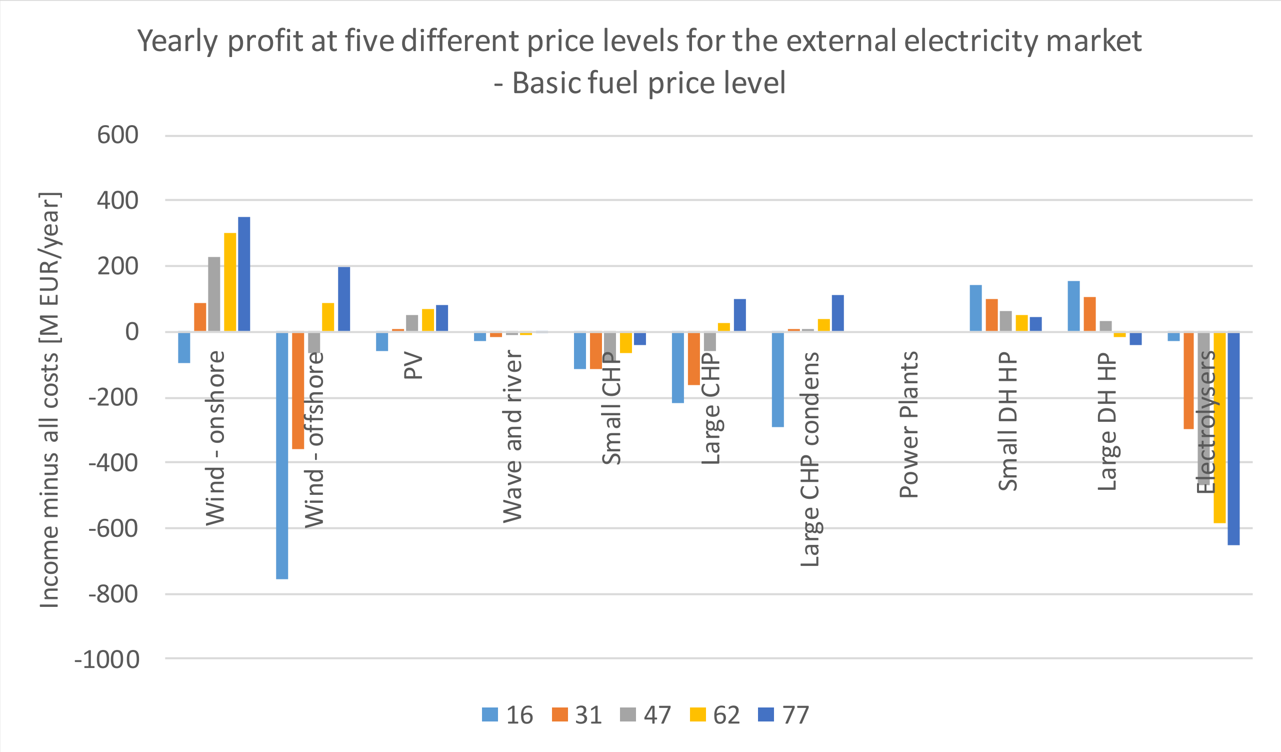

Figure 74 – Yearly profit for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

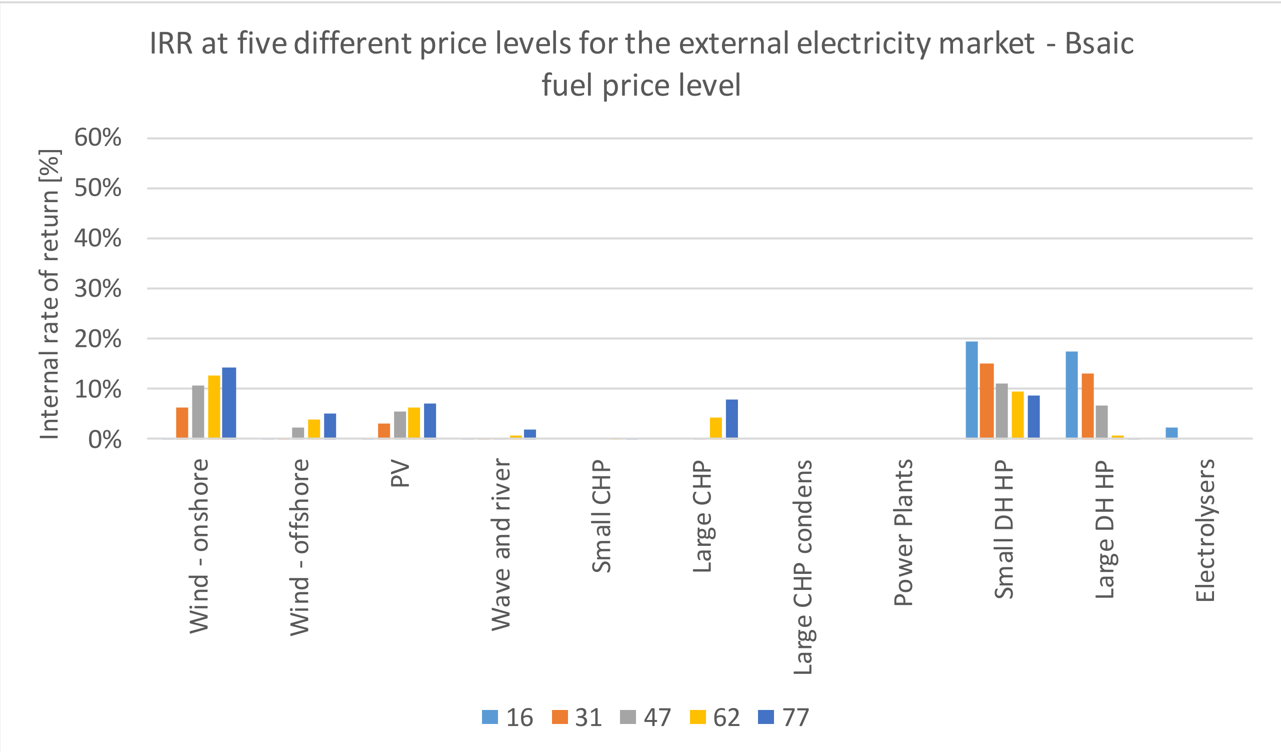

Figure 75 – Internal rate of return for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

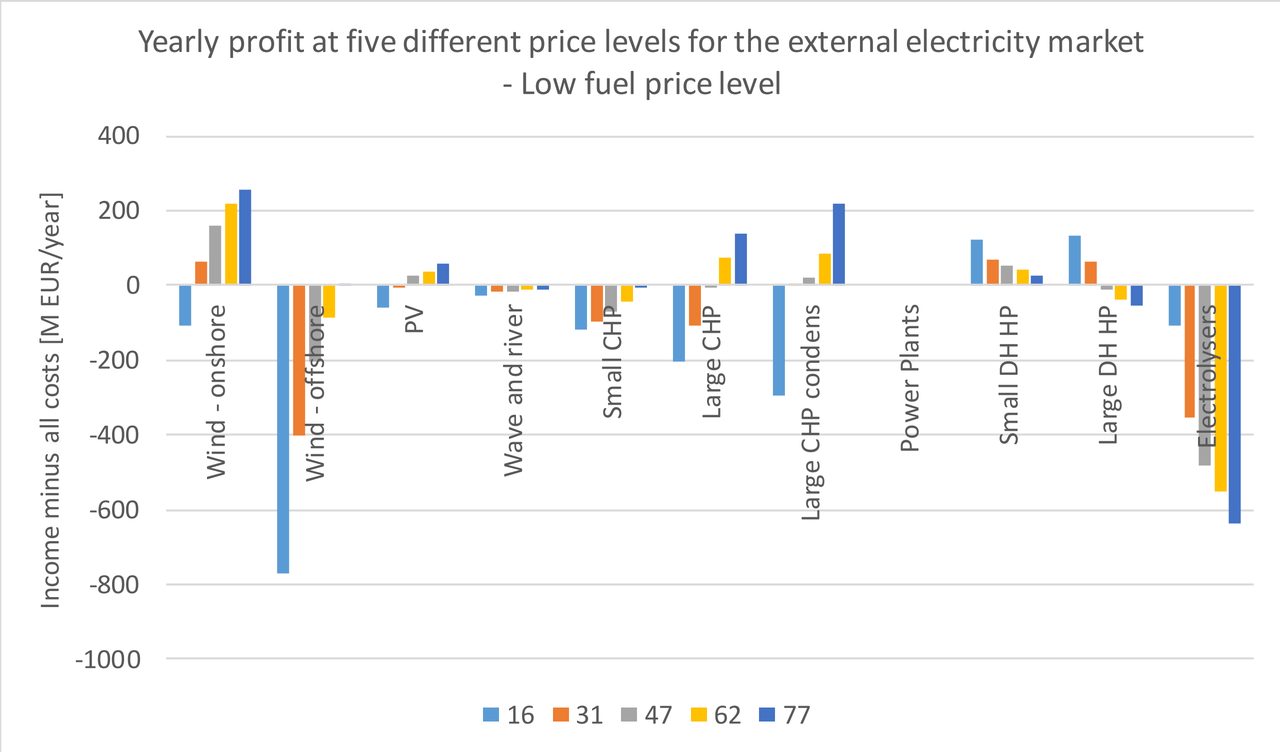

Figure 76 – Yearly profit for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

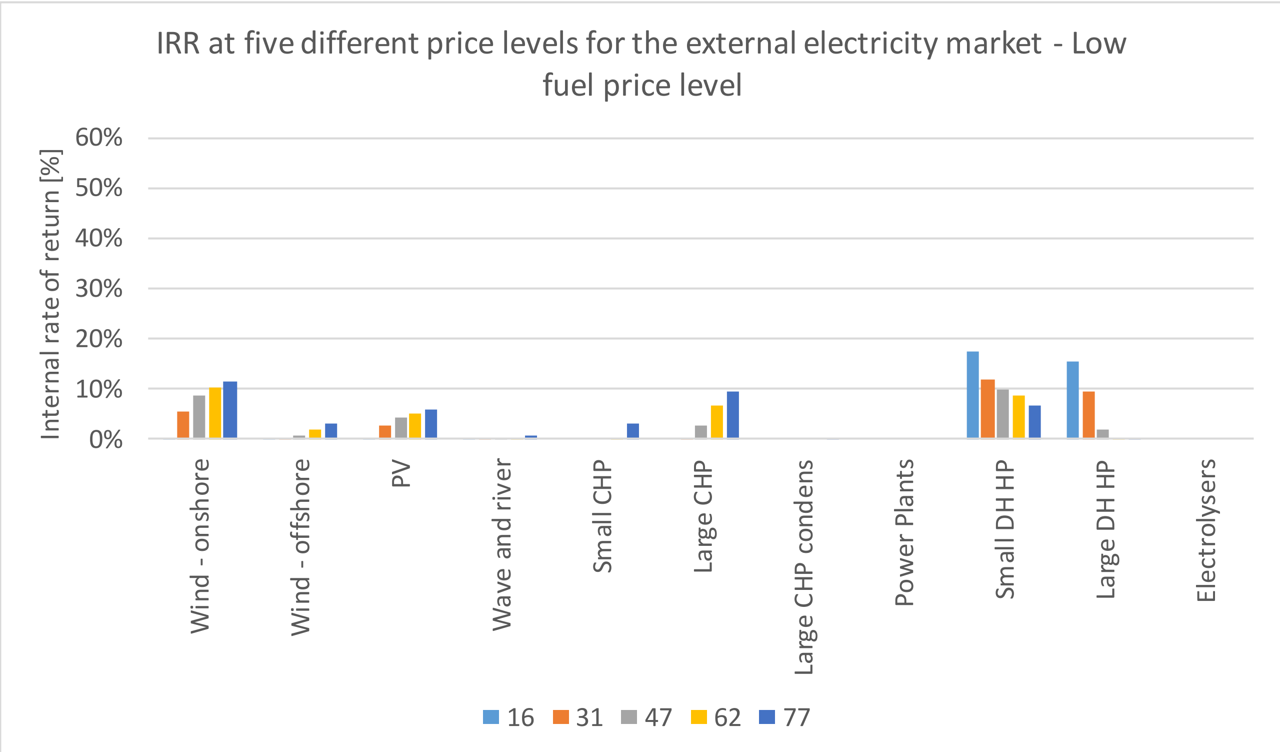

Figure 77 – Internal rate of return for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

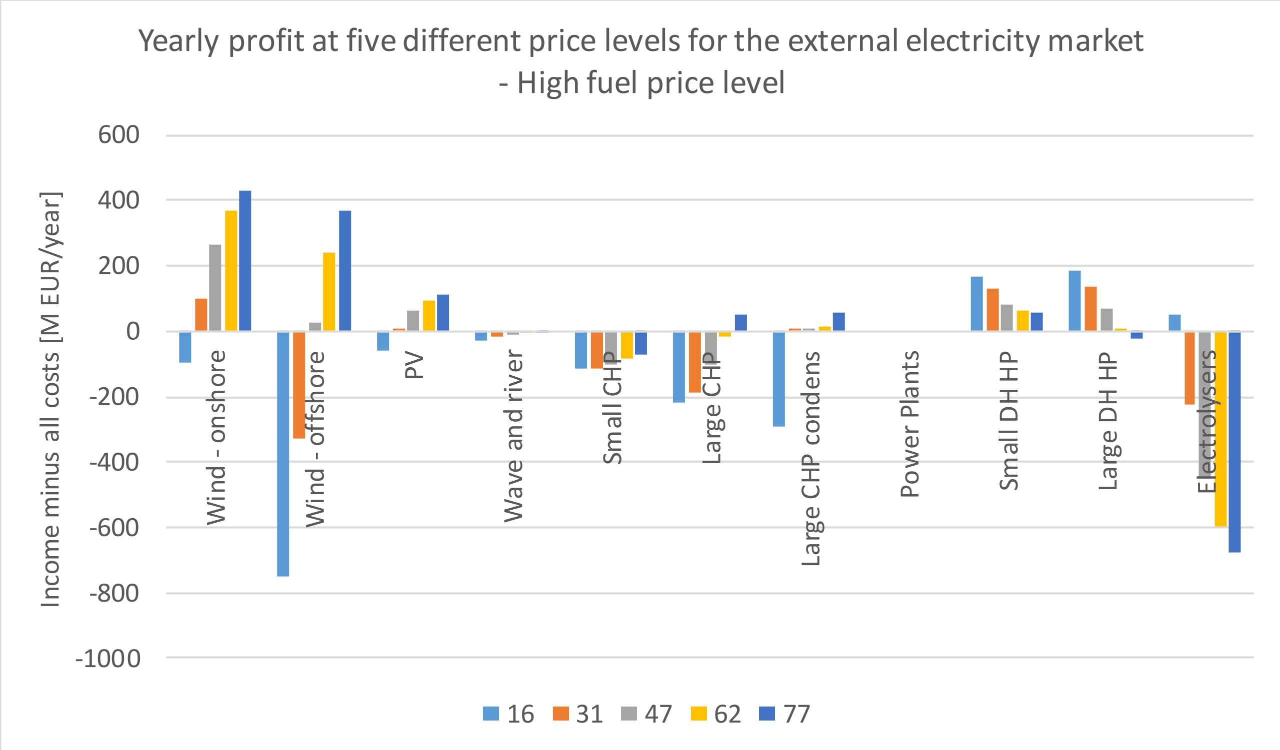

Figure 78 – Yearly profit for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

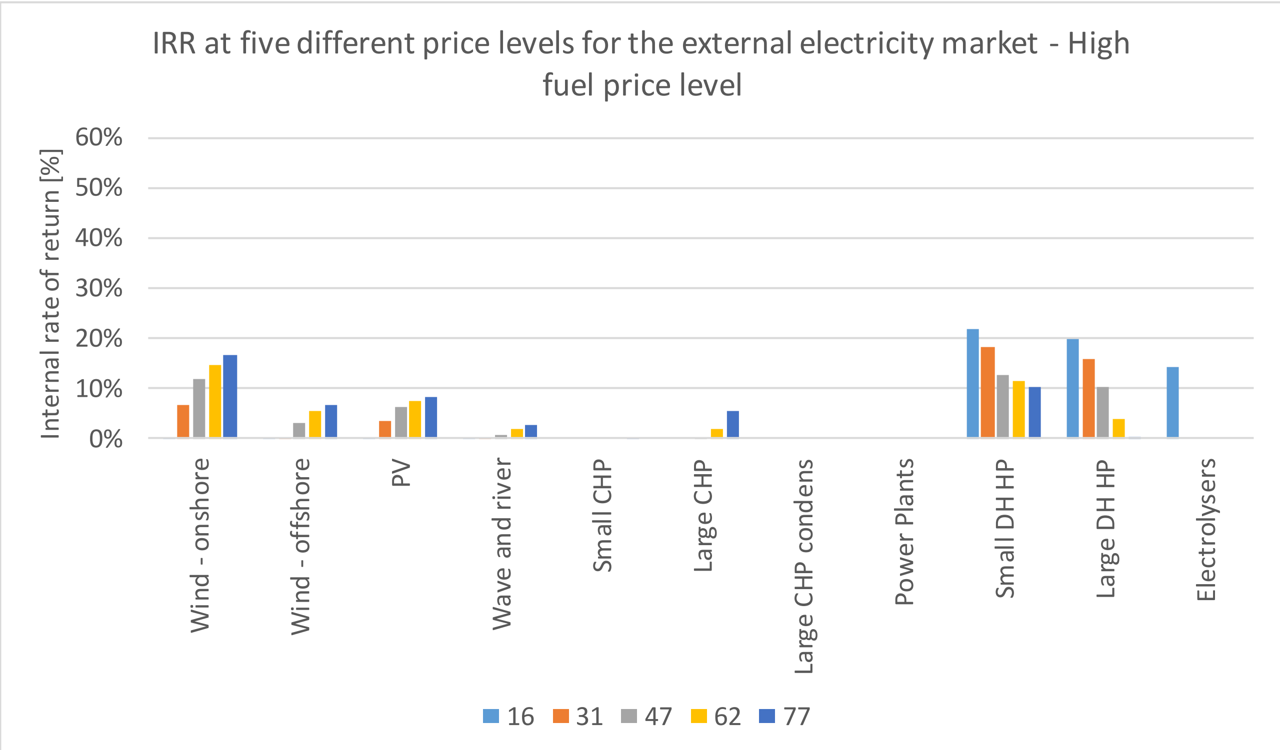

Figure 79 – Internal rate of return for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

Figure 80 shows the lowest value for the produced hydrogen to make the electrolysers (excl. H_2 storage) feasible.

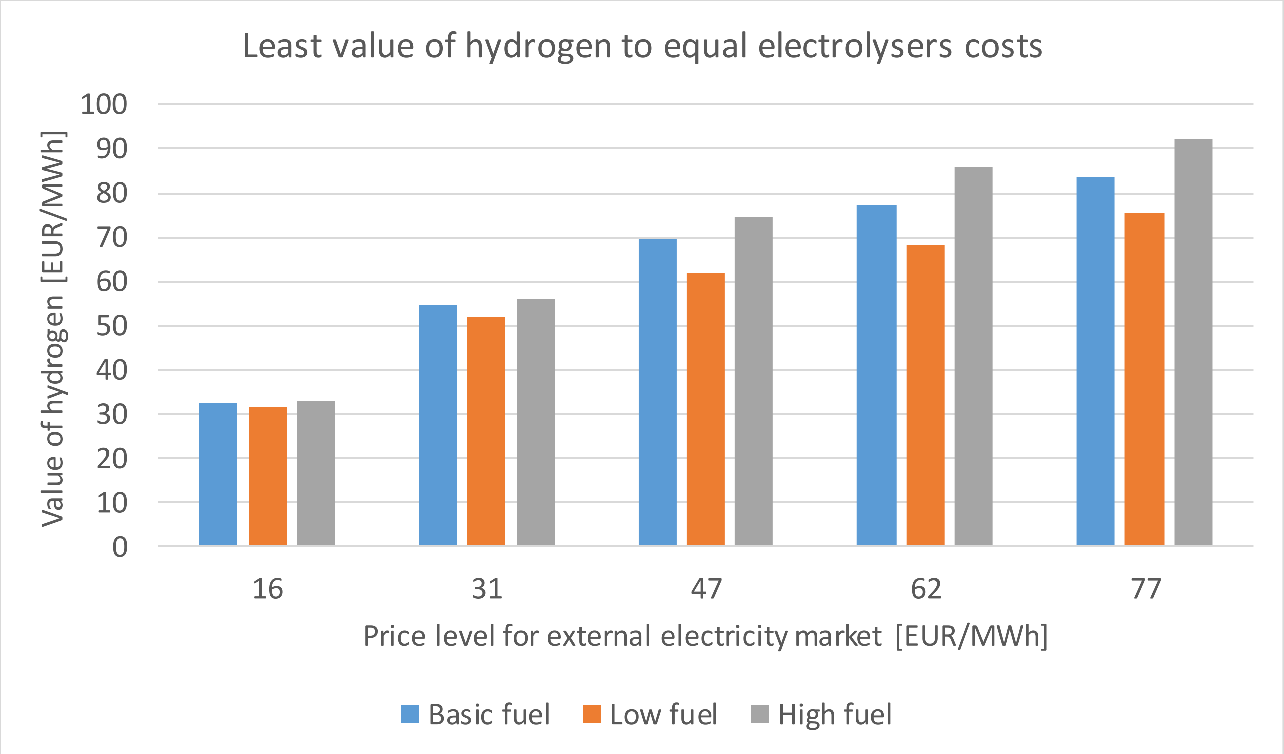

Figure 80 – Least value of hydrogen per MWh produced to equal the costs of operating the electrolysers at each fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

8 IDA 2050

8.1 Overview of scenario

Table 22 shows an overview of the main technical and economic characteristic of the electricity producing and main electricity consuming units in the scenario.

General data for units							
	Electric capacity	Electric efficiency	Thermal capacity	Thermal efficiency	Total investment	Annualised investment	Annual fixed O&M
	[MW]	*[%]*	*[MW]*	*[%]*	*[M EUR]*	*[M EUR/a]*	*[M EUR/a]*
Electricity producing units							
Wind - onshore	5000	-	-	-	4500	230	130
Wind - offshore	14000	-	-	-	29680	1514	956
PV	5000	-	-	-	3450	149	35
Wave and river	300	-	-	-	480	24	9
Small CHP	1500	52%	1125	39%	1800	103	68
Large CHP (excl. Condensing)	3500	52%	2625	39%	2800	161	106
- Large CHP condensing operatio	*4500*	*62%*	-	-	*900*	*49*	*29*
Power plants	0	0%	-	-	0	0	0
Flexible electricity consumption units							
Small DH HP	300	-	1050	350%	870	50	17
Large DH HP	400	-	1400	350%	1160	67	23
Electrolysers	9009	-	-	-	2523	211	76

Table 22 – Overview of relevant units' capacities, efficiencies, investment costs, and annual fixed operation and maintenance (O&M)

For "Electrolysers", only the actual electrolysers are included, meaning that e.g. H2 storage is not included. For "Large CHP (excl. Condensing)", the capacities and efficiencies are only for CHP operation. "Large CHP condensing operation" is the full condensing capacity of the large CHP units, where the investment and fixed O&M costs cover the difference between the electric capacity in CHP operation and the condensing electric capacity.

Figure 81 shows the yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh).

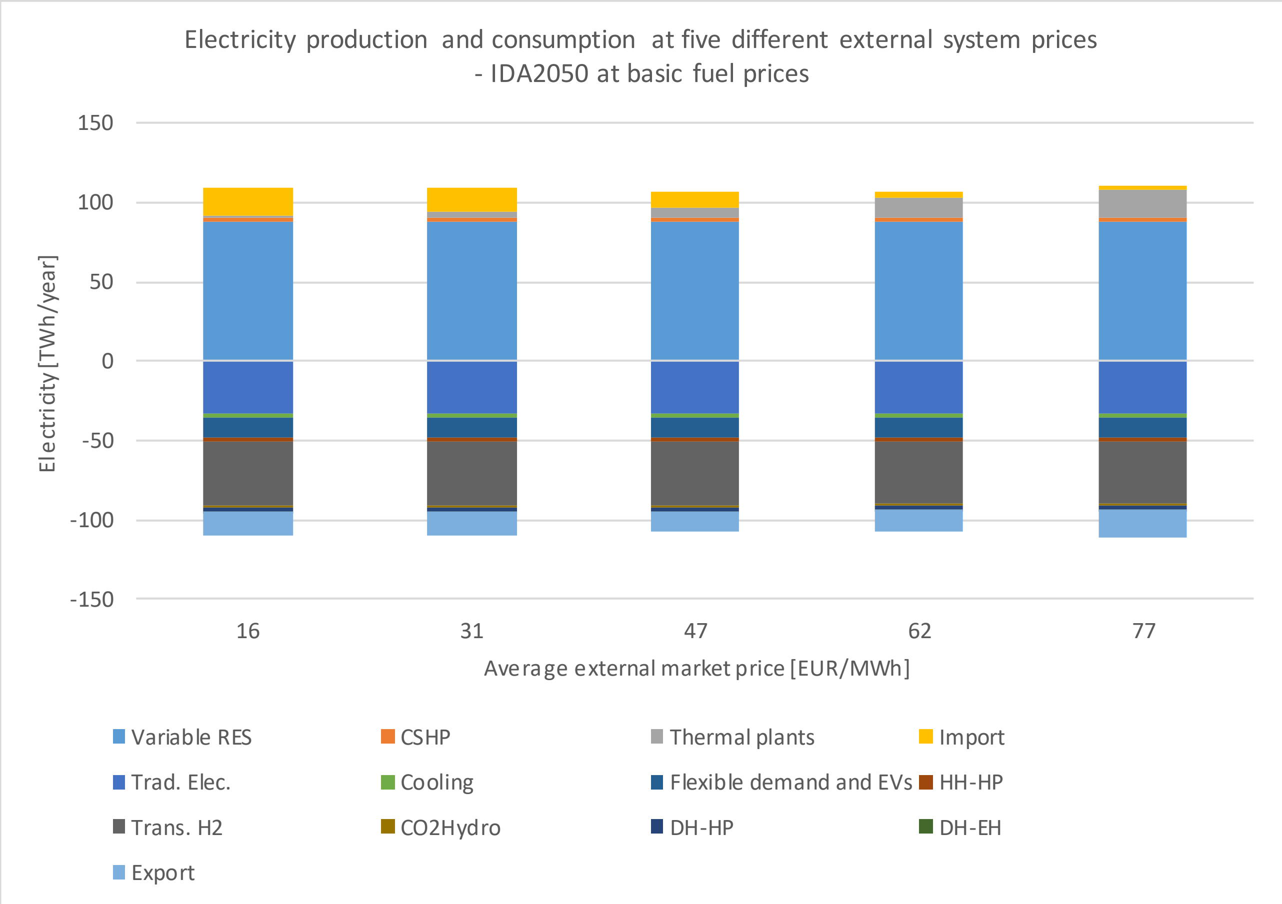

Figure 81 - Yearly electricity production and consumption at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). RES: Renewable Energy Sources, CSHP: Industrial Combined Heat & Power (incl. waste incineration), HH: Households, HP: Heat Pumps, EV: Electric Vehicle, DH: District Heating, EH: Electric Heating.

8.2 Duration curves for electricity consumption and production

The duration curves shown in this section are only for the average external electricity market price of 77 EUR/MWh.

Figure 82 show the duration curves for different types of residual electricity demands. Residual electricity demand is here understood as the electricity demand minus the variable RES electricity production in any given hour. “Residual hourly fixed” are demands that are fixed on an hourly basis (includes e.g. traditional electricity demands). “Residual hourly and yearly fixed” are both the “Residual hourly fixed” as well as any electricity demands that are fixed on a yearly basis (includes e.g. flexible charged electric vehicles). “All residual” are all residual electricity demands (includes e.g. heat pumps in district heating). Figure 83 show the electricity production duration curves for CSHP, variable RES, and thermal plants.

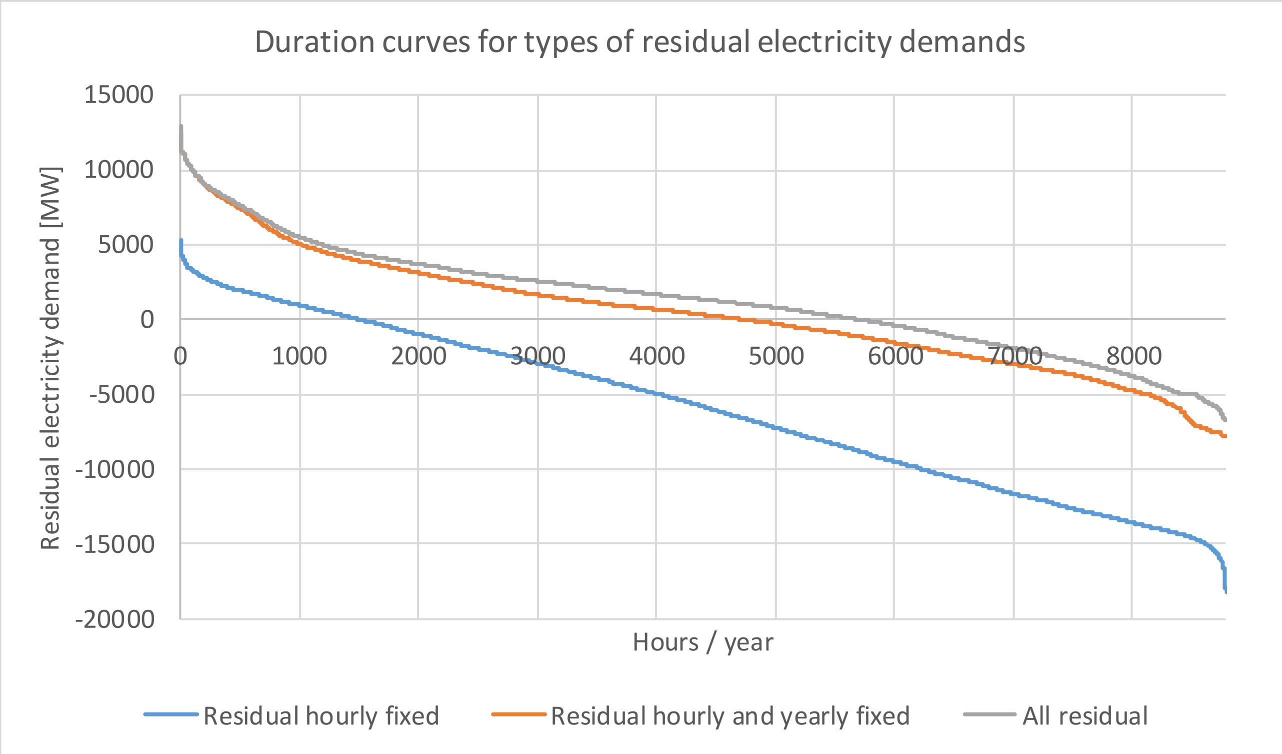

Figure 82 – Duration curves for different types of residual electricity demands at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

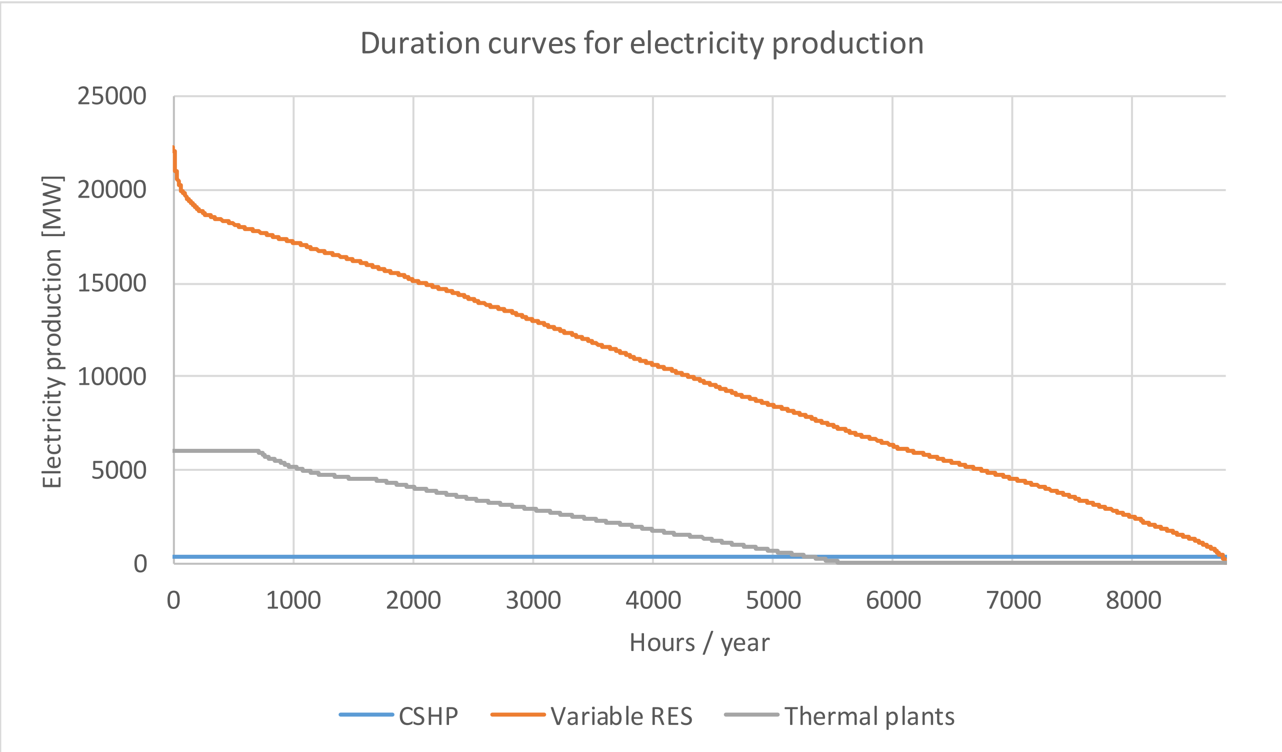

Figure 83 – Duration curves for electricity production by different unit types at basic fuel price level and a starting point for the electricity market price on the external markets of 77 EUR/MWh.

8.3 Electricity prices

Figure 84, Figure 85, and Figure 86 show for each of the three fuel price levels the resulting hourly electricity market system price using five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). Table 23, Table 24, and Table 25 show the corresponding resulting average, minimum, and maximum electricity price in the simulation.

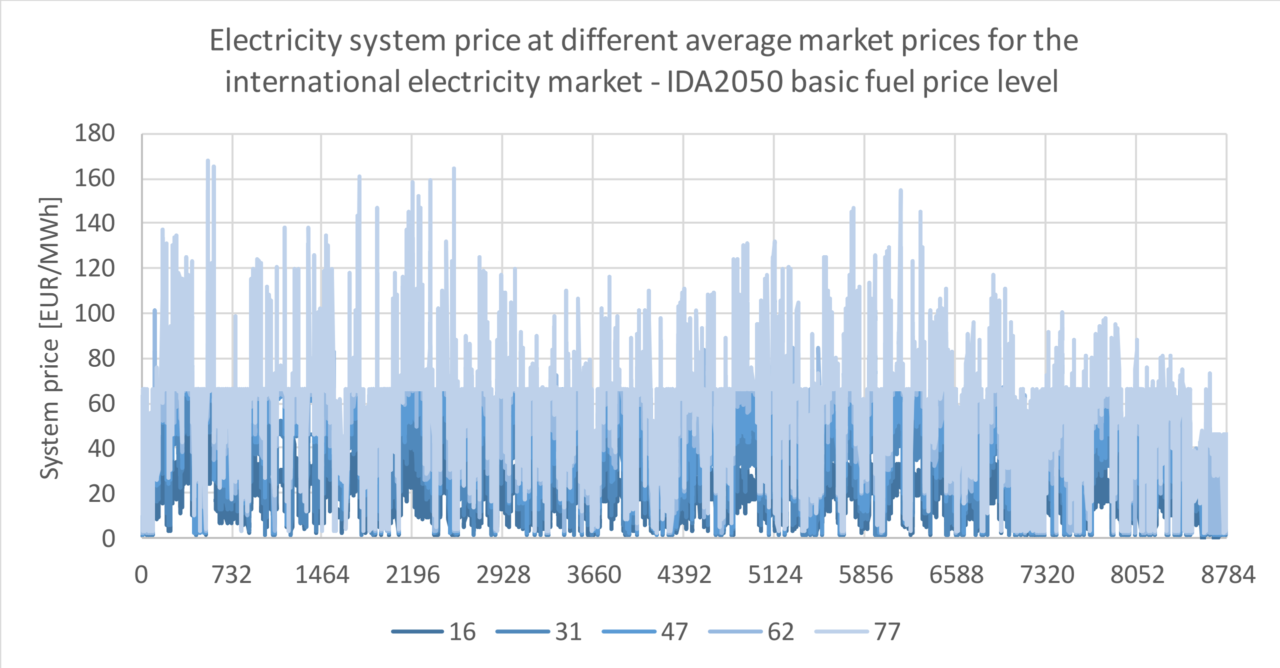

Figure 84 – Hourly system price on Nord Pool Spot at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	17	32	44	53	58
Resulting min	0	1	1	2	2
Resulting max	63	72	99	128	168

Table 23 - Resulting yearly average, minimum and maximum electricity prices at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

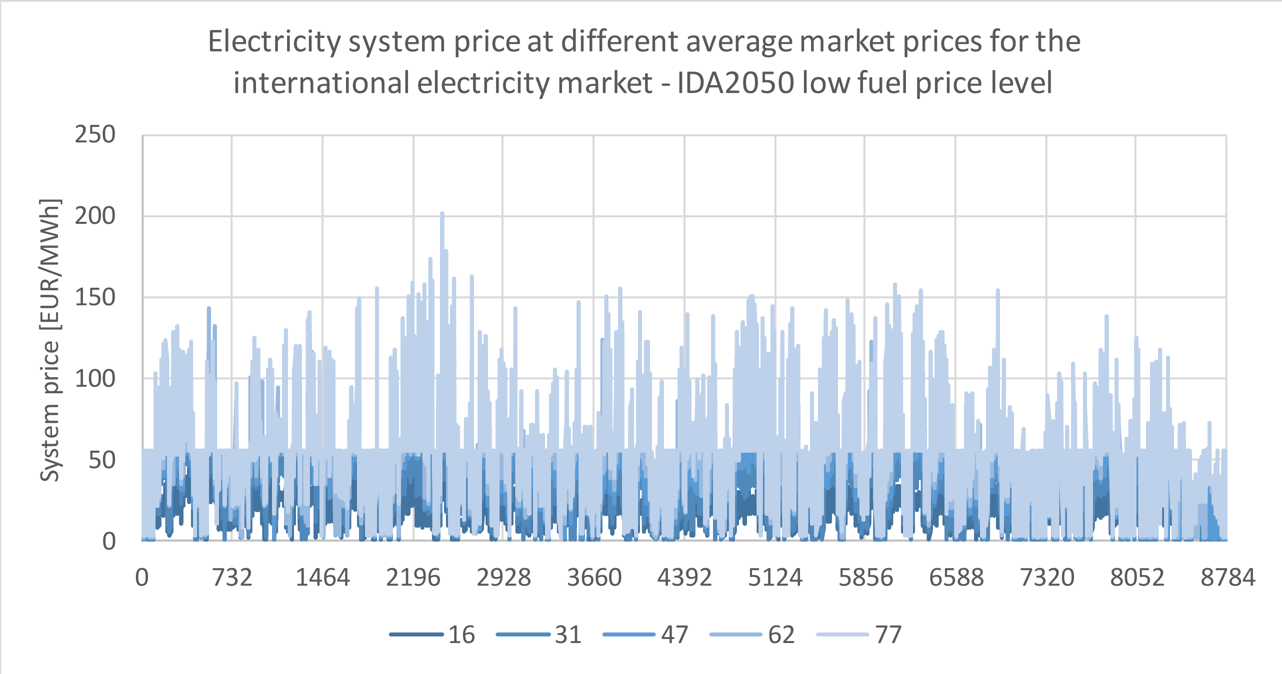

Figure 85 – Hourly system price on Nord Pool Spot at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	17	31	42	48	53
Resulting min	0	1	1	2	2
Resulting max	53	69	96	143	202

Table 24 - Resulting yearly average, minimum and maximum electricity prices at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

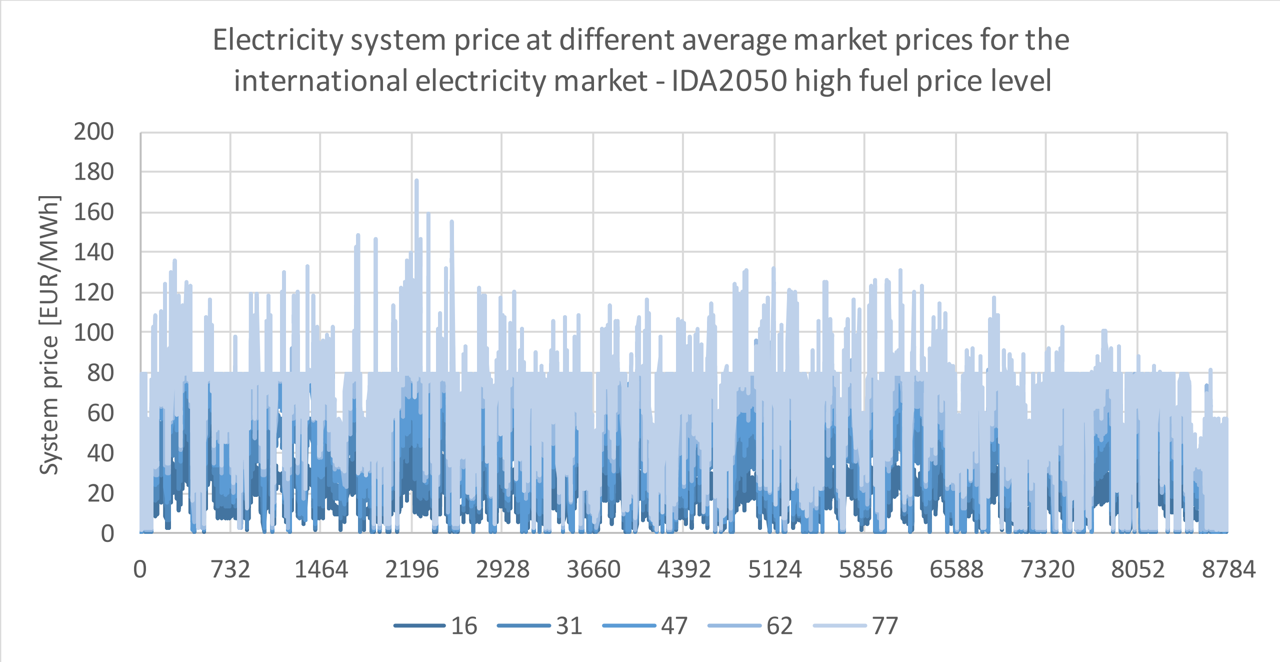

Figure 86 – Hourly system price on Nord Pool Spot at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

	Yearly average electricity price on external electricty markets [EUR/MWh]				
	16	**31**	**47**	**62**	**77**
Resulting average	17	33	46	57	64
Resulting min	0	1	1	2	2
Resulting max	63	79	103	128	176

Table 25 - Resulting yearly average, minimum and maximum electricity prices at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

8.4 Marginal activated unit

The purpose of this section is to identify the marginal activated unit in the simulated energy system. This is done by first separating the array for the electricity market price into arrays with the marginal price of each unit being the lower limit of an array and the next marginal most expensive unit being the upper limit. E.g. “Incr. B2 decr. EB2” has a marginal price of 38 and the next least expensive unit is “Incr. CHP2 decr. B2” with a marginal price of 67, resulting in the “Incr. B2 decr. EB2” array being prices between 38 and 67. After the arrays have been established, it is for each hour checked whether the activated technology was in fact in use or not. If not, then if there is variable RES in operation this becomes the marginal activated unit. If there is no variable RES in operation, then it that hour is added to the “Rest” category (i.e. the external market is the marginal “unit”). This approach only account for the units activated within the simulated energy system and does not account for what units are activated outside of the simulated energy system in case of import and export of electricity.

This is done for each of the three fuel price levels, as well as the five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). See Figure 87, Figure 88, and Figure 89.

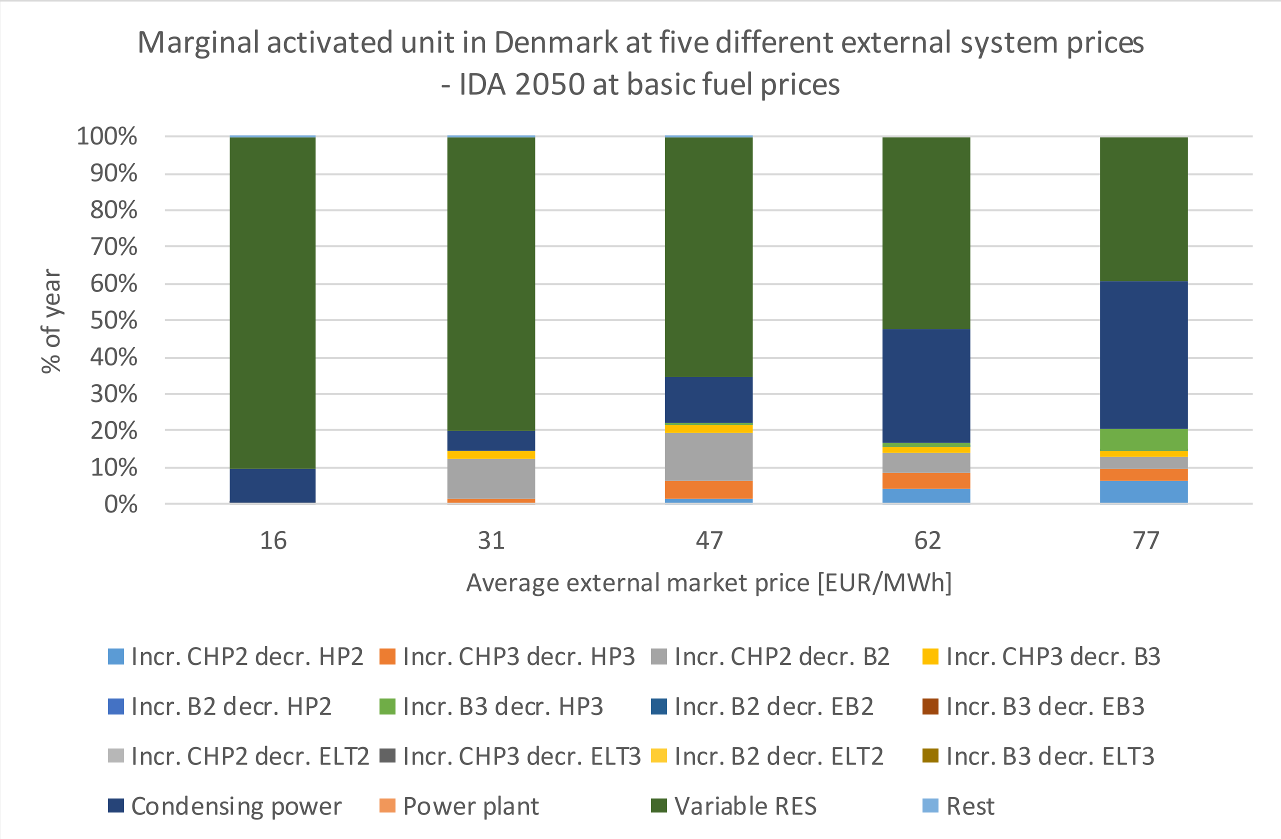

Figure 87 – Marginal activated unit in Denmark at the basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

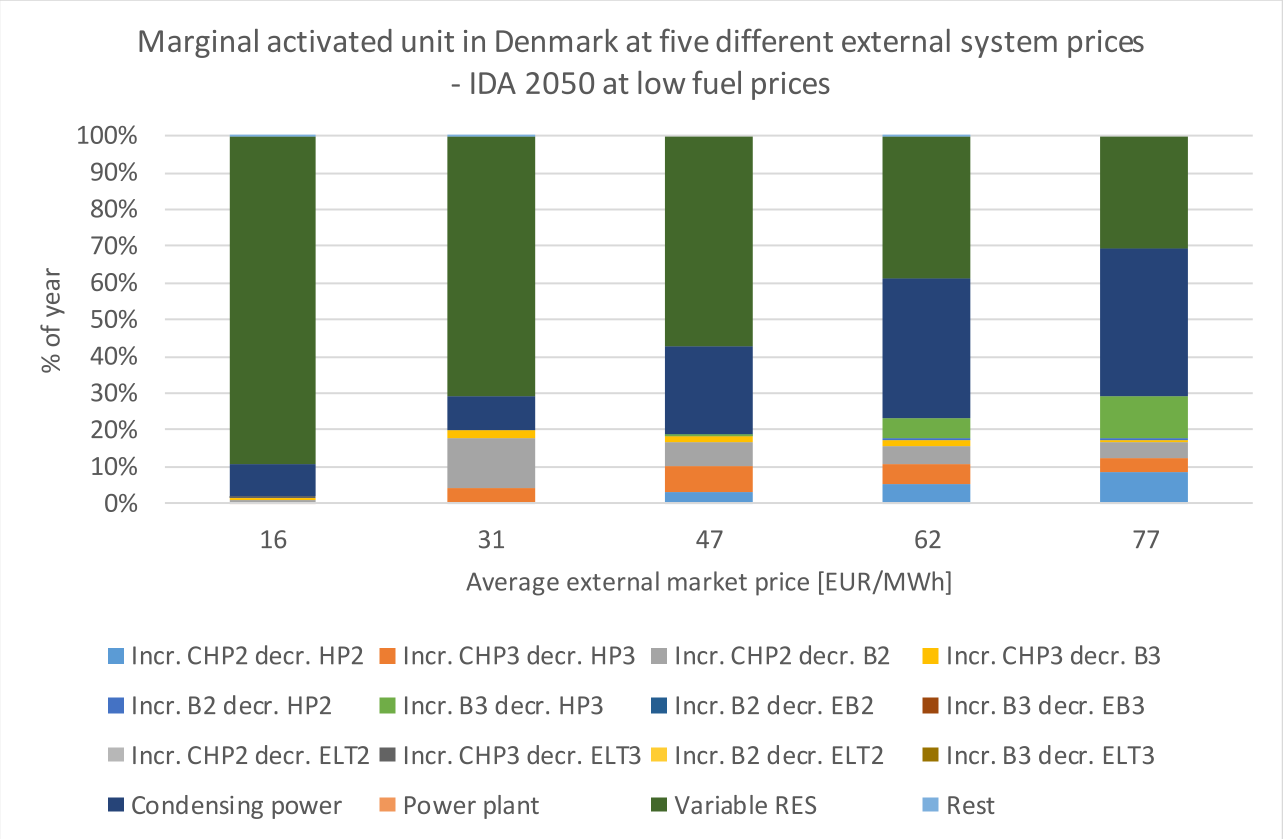

Figure 88 – Marginal activated unit in Denmark at the low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

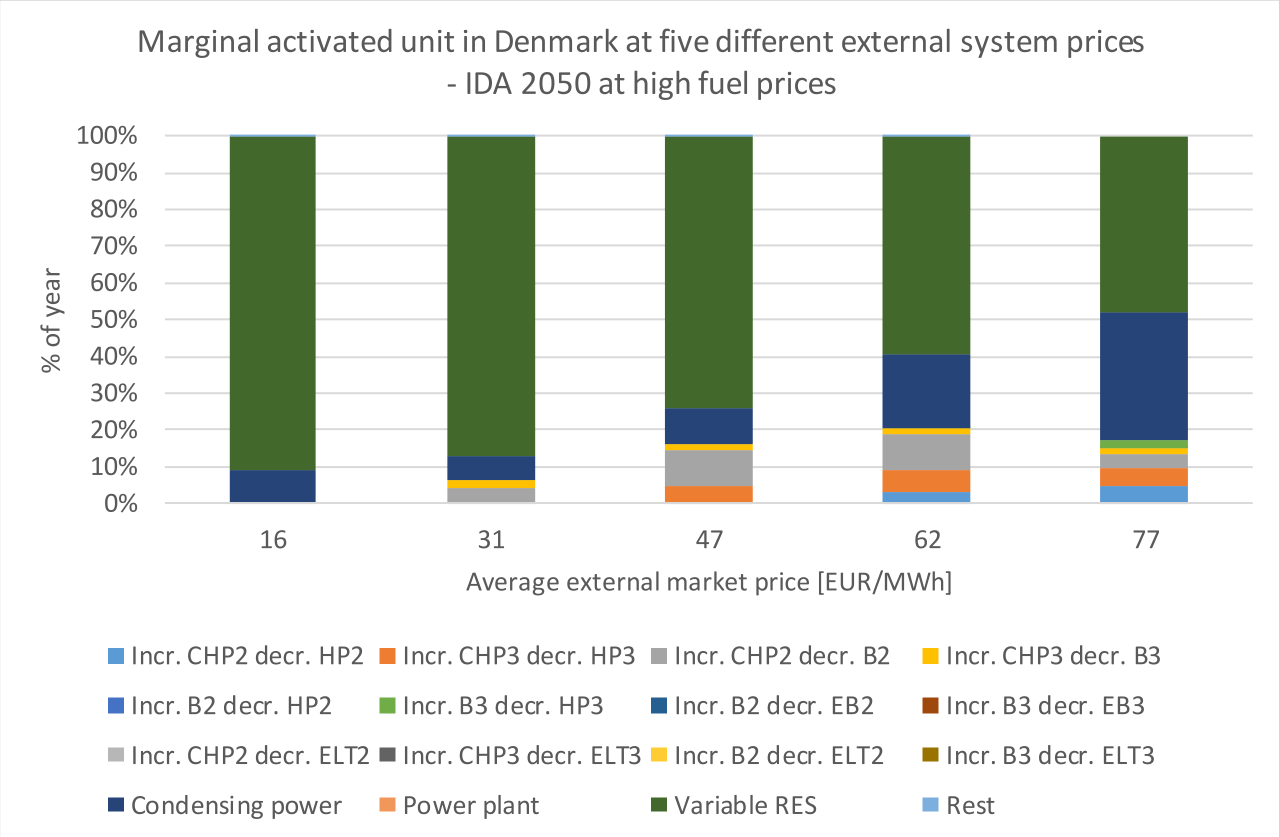

Figure 89 – Marginal activated unit in Denmark at the high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh). B: Fuel Boiler, HP: Heat Pumps, EB: Electric Boilers, ELT: Electrolysers, RES: Renewable Energy Sources. "2" indicates units connected to smaller district heating areas, and "3" indicates units connected to large district heating areas.

8.5 Profit analysis

The aim of this analysis is to identify which types of units are expected to be able to cover their own costs in the current Nord Pool Spot regime. Only costs directly related to the specific units are included (investment, fixed O&M, variable O&M, fuel costs, and CO_2-costs). As such, potential related costs, e.g. grid costs and storage costs, are not included. For the income, only sale of electricity on Nord Pool Spot (as modelled in EnergyPLAN), sale of produced district heating and sale of hydrogen are included. For sale of district heating, it is assumed that the value of the produced heat is equal to the short-marginal cost of an average fuel boiler in the corresponding district heating group.

Figure 90, Figure 92, and Figure 94 show the yearly profit of each unit type where a discount rate of 3% has been used. Figure 91, Figure 93, and Figure 95 show the corresponding internal rate of return (IRR). The only incomes being sale of electricity on Nord Pool Spot, sale of heat for district heating, and sale of hydrogen. In these figures, the sale of hydrogen is simply assumed to equal the natural gas price. Figure 96 shows what the lowest value for the produced hydrogen should be to make the electrolysers feasible. Each figure represents a different fuel price level.

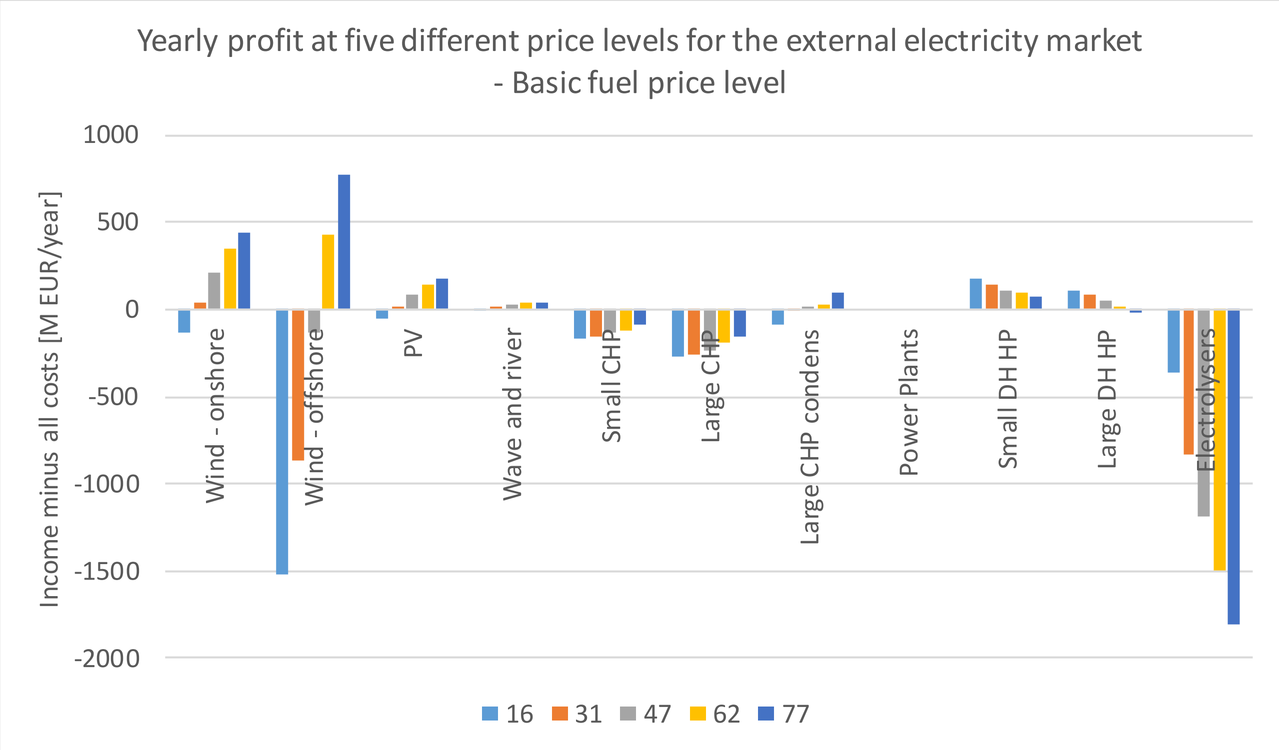

Figure 90 – Yearly profit for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

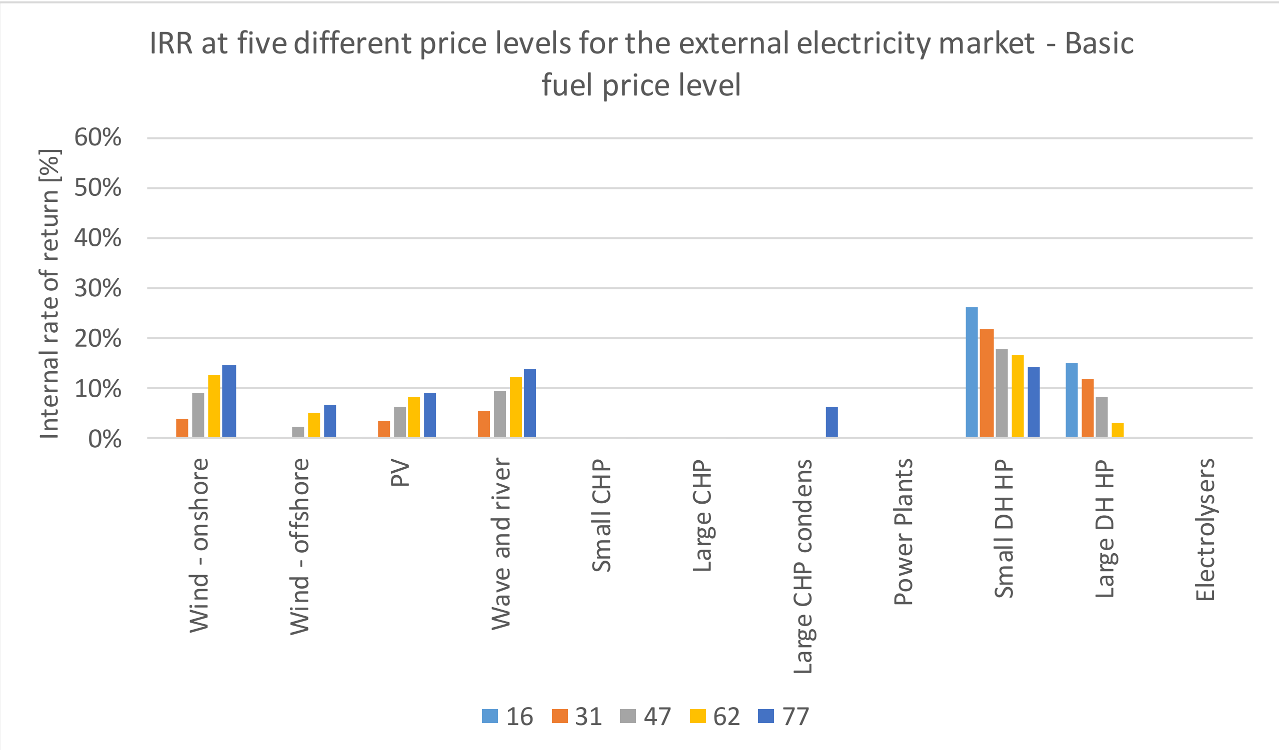

Figure 91 – Internal rate of return for the different types of units at basic fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

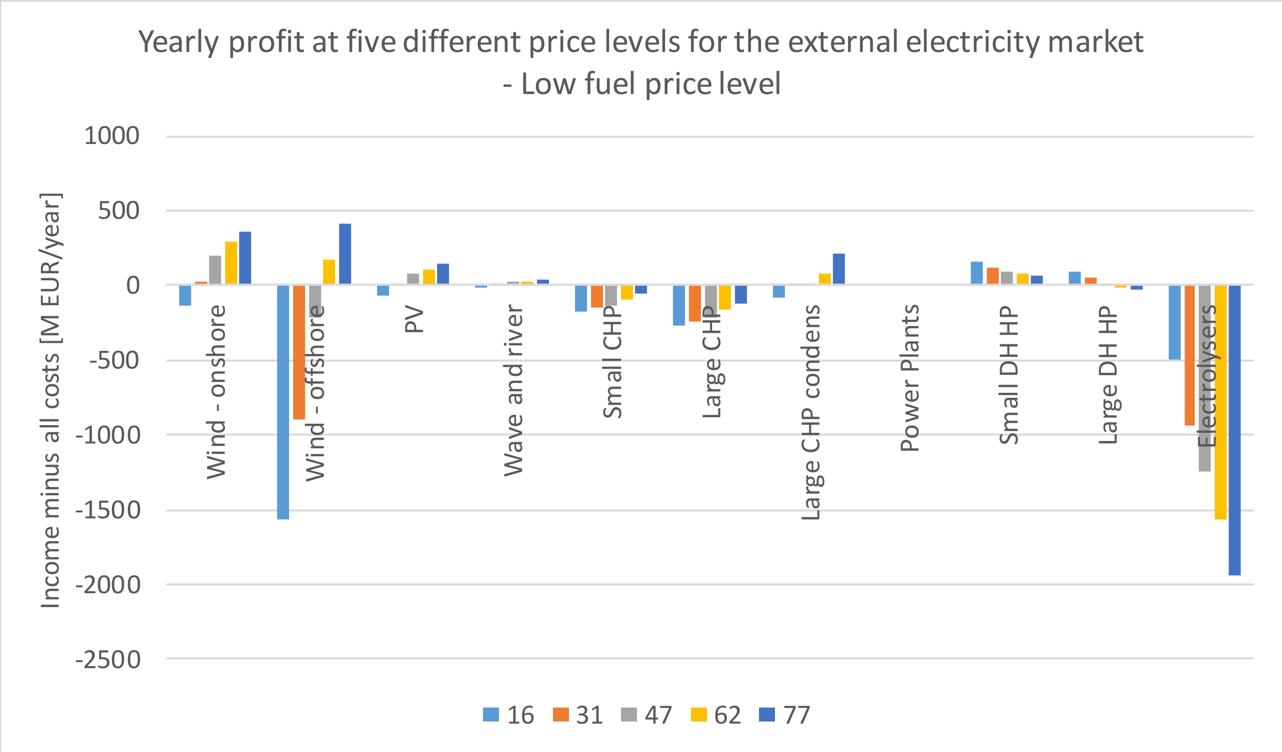

Figure 92 – Yearly profit for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

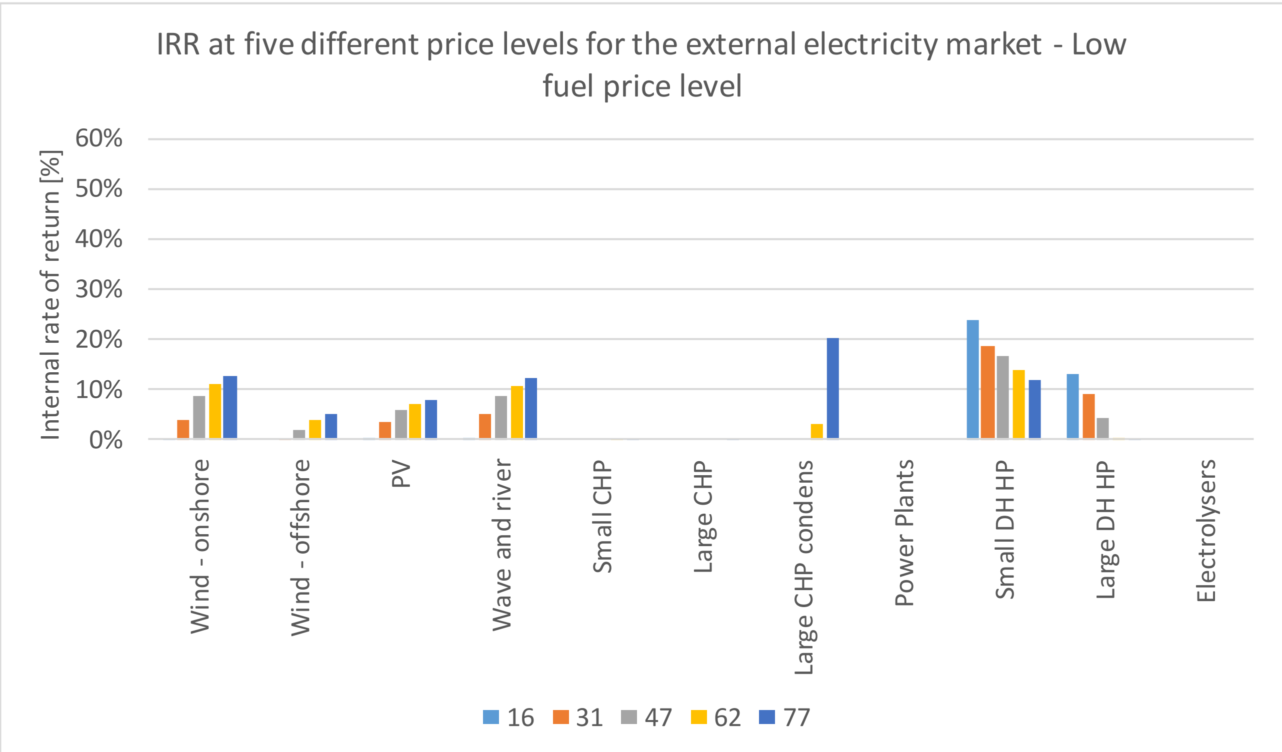

Figure 93 – Internal rate of return for the different types of units at low fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

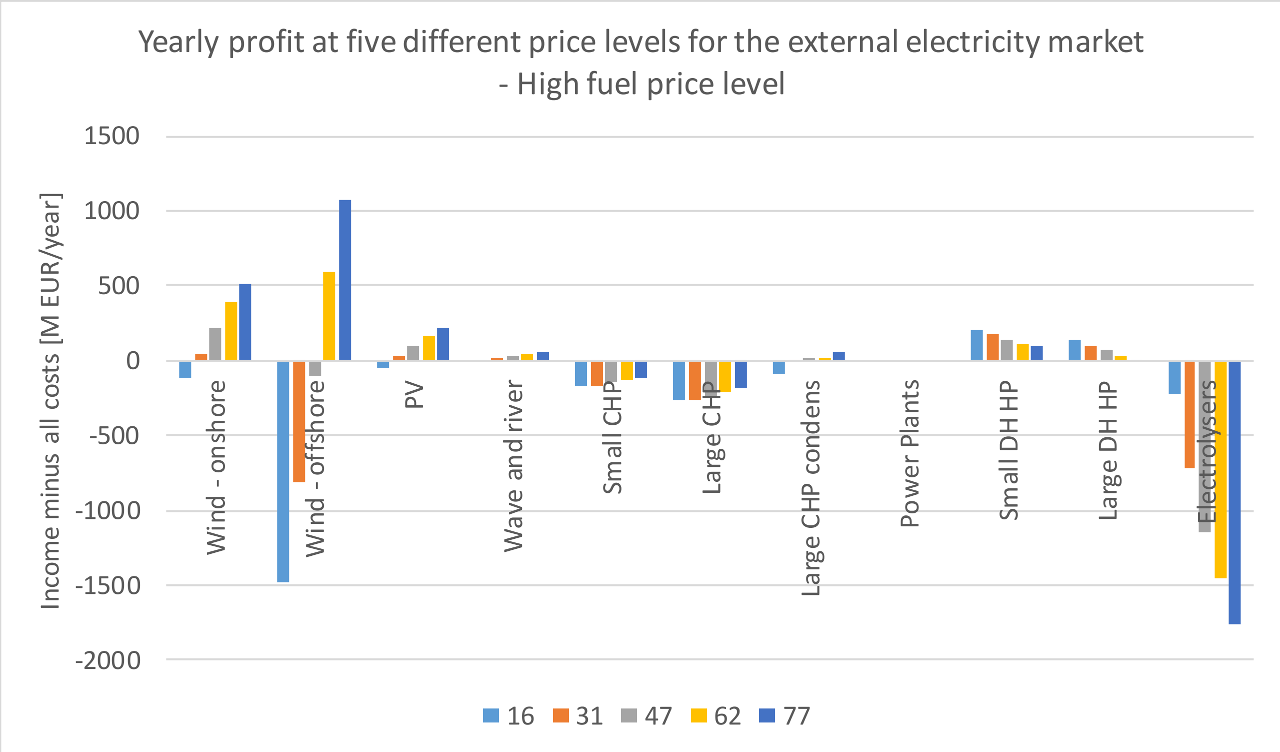

Figure 94 – Yearly profit for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

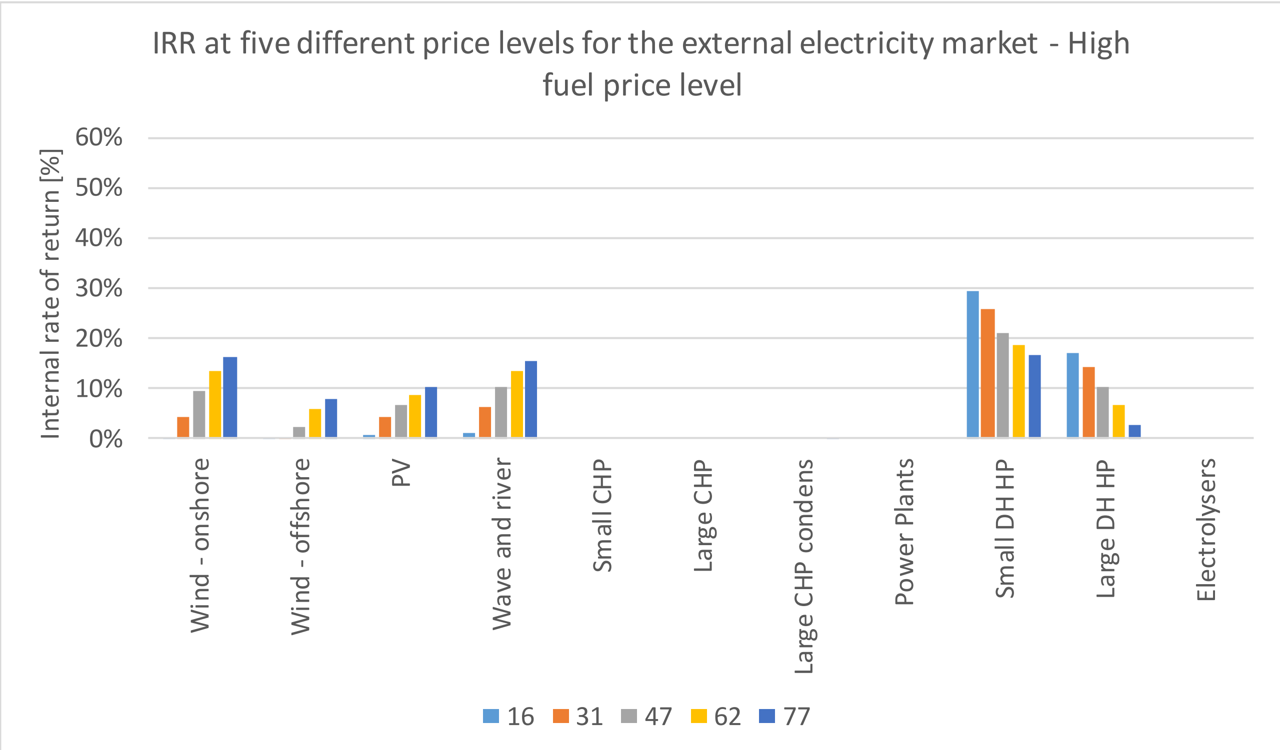

Figure 95 – Internal rate of return for the different types of units at high fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

Figure 96 shows the lowest value for the produced hydrogen to make the electrolysers (excl. H_2 storage) feasible.

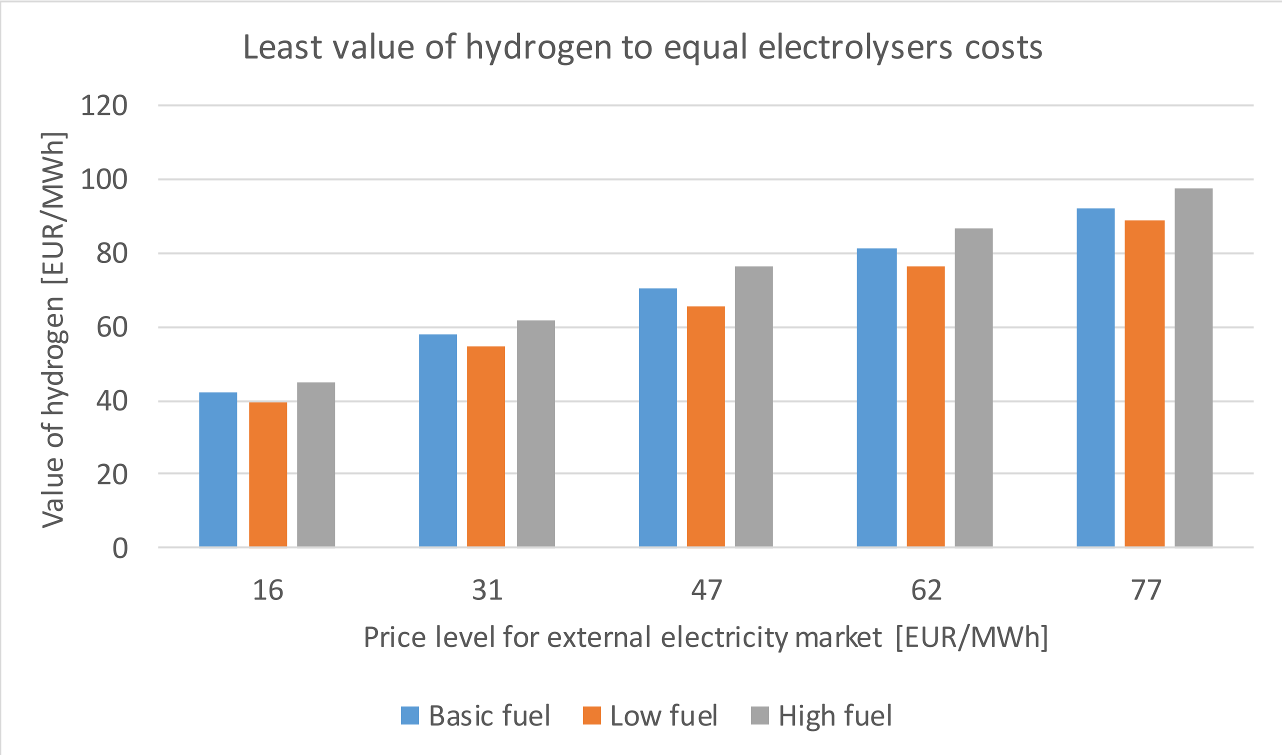

Figure 96 – Least value of hydrogen per MWh produced to equal the costs of operating the electrolysers at each fuel price level and at five different starting points for the electricity market price on the external markets (average price of 16, 31, 47, 62 and 77 EUR/MWh)

9 The gas and liquid fuel markets in EnergyPLAN

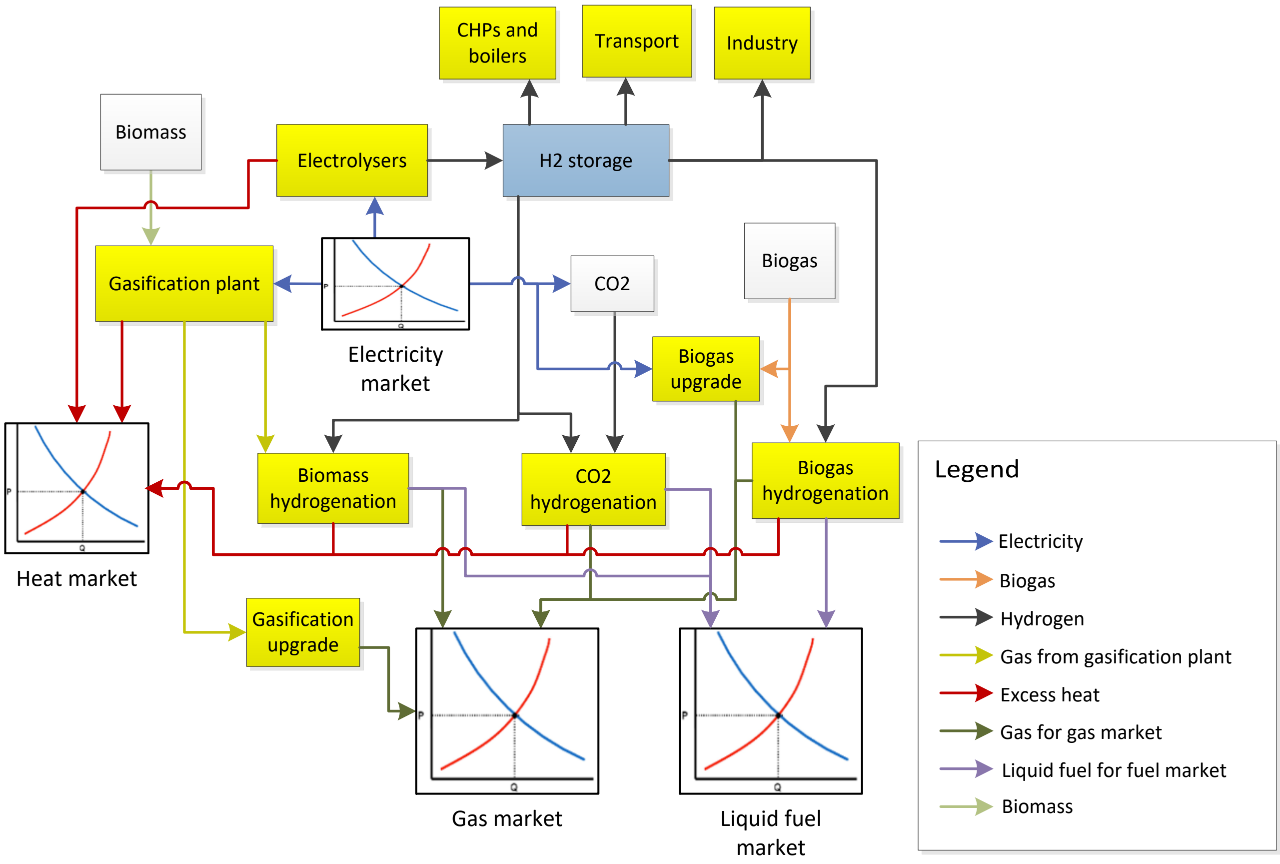

Figure 97 – The setup of gas and liquid fuel infrastructure and its connection to different markets in EnergyPLAN

10 References

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